

UNITED STATES PATENT APPLICATION FOR:

**METHODS AND APPARATUS FOR CEMENTING DRILL STRINGS IN PLACE
FOR ONE PASS DRILLING AND COMPLETION OF OIL AND GAS WELLS**

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CERTIFICATION OF MAILING UNDER 37 C.F.R. 1.10

I hereby certify that this New Application and the documents referred to as enclosed therein are being deposited with the United States Postal Service on December 5, 2003, in an envelope marked as "Express Mail United States Postal Service", Mailing Label No. EV335470042US, addressed to: Commissioner for Patents, Mail Stop PATENT APPLICATION, P.O. Box 1450, Alexandria, VA 22313-1450

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Name

5 December 2003
Date of signature

1 METHODS AND APPARATUS FOR CEMENTING DRILL STRINGS IN PLACE
2 FOR ONE PASS DRILLING AND COMPLETION OF OIL AND GAS WELLS
3
4
5

6 PRIORITY FROM U.S. PATENT APPLICATIONS
7

8 The present application is a continuation-in-part
9 (C.I.P.) application of co-pending U.S. Patent Application
10 Serial No. 10/189,570, filed July 6, 2002, that is entitled
11 "Installation of One-Way Valve After Removal of Retrievable
12 Drill Bit to Complete Oil and Gas Wells", which is fully
13 incorporated herein by reference.
14

15 U.S. Patent Application Serial No. 10/189,570 is a
16 continuation-in-part (C.I.P.) application of co-pending
17 U.S. Patent Application Serial No. 10/162,302, filed June 4,
18 2002, that is entitled "Closed-Loop Conveyance Systems for
19 Well Servicing", which is fully incorporated herein by
20 reference.
21

22 U.S. Patent Application Serial No. 10/162,302 is a
23 continuation-in-part (C.I.P.) application of U.S. Patent
24 Application Serial No. 09/487,197, filed January 19, 2000,
25 that is entitled "Closed-Loop System to Complete Oil and Gas
26 Wells", now U.S. Patent No. 6,397,946, that issued on June 4,
27 2002, which is fully incorporated herein by reference.
28

29 U.S. Patent Application Serial No. 09/487,197 was
30 corrected by a Certificate of Correction, which was "Signed
31 and Sealed" on the date of October 1, 2002, to be a
32 continuation-in-part (C.I.P.) of U.S. Patent Application
33 Serial No. 09/295,808, filed April 20, 1999, that is entitled
34 "One Pass Drilling and Completion of Extended Reach Lateral

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1 Wellbores with Drill Bit Attached to Drill String to Produce
2 Hydrocarbons from Offshore Platforms", now U.S. Patent
3 No. 6,263,987, that issued on July 24, 2001, which is fully
4 incorporated herein by reference.

5
6 U.S. Patent Application Serial No. 09/295,808 is a
7 continuation-in-part (C.I.P.) of U.S. Patent Application
8 Serial No. 08/708,396, filed September 3, 1996, that is
9 entitled "Method and Apparatus for Cementing Drill Strings in
10 Place for One Pass Drilling and Completion of Oil and Gas
11 Wells", now U.S. Patent No. 5,894,897, that issued on April
12 20, 1999, which is fully incorporated herein by reference.

13
14 U.S. Patent Application Serial No. 08/708,396 is a
15 continuation-in-part (C.I.P.) of U.S. Patent Application
16 Serial No. 08/323,152, filed October 14, 1994, that is
17 entitled "Method and Apparatus for Cementing Drill Strings
18 in Place for One Pass Drilling and Completion of Oil and
19 Gas Wells", now U.S. Patent No. 5,551,521, that issued on
20 September 3, 1996, which is fully incorporated herein by
21 reference.

22
23 Applicant claims priority from and the benefit of
24 the above six U.S. Patent Applications having Serial
25 Nos. 10/189,570, 10/162,302, 09/487,197, 09/295,808,
26 08/708,396, and 08/323,152.

27
28
29 **RELATED APPLICATIONS**

30
31 The present application relates to U.S. Patent
32 Application Serial No. 09/375,479, filed August 16, 1999,
33 that is entitled "Smart Shuttles to Complete Oil and Gas
34 Wells", now U.S. Patent No. 6,189,621, that issued on

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1 February 20, 2001, which is fully incorporated herein by
2 reference.

3
4 The present application further relates to PCT
5 Application Serial No. PCT/US00/22095, filed August 9, 2000,
6 that is entitled "Smart Shuttles to Complete Oil and Gas
7 Wells", which is fully incorporated herein by reference.
8 This PCT Application corresponds to U.S. Patent Application
9 Serial No. 09/375,479. This application has also been
10 published elsewhere as WO 01/12946 A1 (on 2/22/2001);
11 EP 1210498 A1 (on 6/5/2002); CA 2382171 AA (on 2/22/2001);
12 and AU 0067676 A5 (on 3/13/2001).
13

14 The present application also relates to U.S. Patent
15 Application Serial No. 09/294,077, filed April 18, 1999, that
16 is entitled "One Pass Drilling and Completion of Wellbores
17 with Drill Bit Attached to Drill String to Make Cased
18 Wellbores to Produce Hydrocarbons", now U.S. Patent
19 No. 6,158,531, that issued on December 12, 2000, which is
20 fully incorporated herein by reference.
21
22

23 RELATED U.S. DISCLOSURE DOCUMENTS

24

25 This application further relates to disclosure in U.S.
26 Disclosure Document No. 362582, filed on September 30, 1994,
27 that is entitled in part 'RE: Draft of U.S. Patent
28 Application Entitled "Method and Apparatus for Cementing
29 Drill Strings in Place for One Pass Drilling and Completion
30 of Oil and Gas Wells"', an entire copy of which is
31 incorporated herein by reference.
32

33 This application further relates to disclosure in U.S.
34 Disclosure Document No. 445686, filed on October 11, 1998,

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1 having the title that reads exactly as follows:
2 'RE: -Invention Disclosure- entitled "William Banning Vail
3 III, October 10, 1998"', an entire copy of which is
4 incorporated herein by reference.
5

6 This application further relates to disclosure in U.S.
7 Disclosure Document No. 451292, filed on February 10, 1999,
8 that is entitled in part 'RE: -Invention Disclosure- "Method
9 and Apparatus to Guide Direction of Rotary Drill Bit" dated
10 February 9, 1999"', an entire copy of which is incorporated
11 herein by reference.
12

13 This application further relates to disclosure in U.S.
14 Disclosure Document No. 452648 filed on March 5, 1999 that is
15 entitled in part 'RE: "-Invention Disclosure- February 28,
16 1999 One-Trip-Down-Drilling Inventions Entirely Owned by
17 William Banning Vail III"', an entire copy of which is
18 incorporated herein by reference.
19

20 This application further relates to disclosure in U.S.
21 Disclosure Document No. 455731 filed on May 2, 1999 that is
22 entitled in part 'RE: -INVENTION DISCLOSURE- entitled
23 "Summary of One-Trip-Down-Drilling Inventions"', an entire
24 copy of which is incorporated herein by reference.
25

26 This application further relates to disclosure in U.S.
27 Disclosure Document No. 459470 filed on July 20, 1999 that
28 is entitled in part 'RE: -INVENTION DISCLOSURE ENTITLED
29 "Different Methods and Apparatus to 'Pump-down'.... "',
30 an entire copy of which is incorporated herein by reference.
31

32 This application further relates to disclosure in U.S.
33 Disclosure Document No. 462818 filed on September 23, 1999
34 that is entitled in part "Directional Drilling of Oil and Gas

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1 Wells Provided by Downhole Modulation of Mud Flow", an entire
2 copy of which is incorporated herein by reference.

3
4 This application further relates to disclosure in U.S.
5 Disclosure Document No. 465344 filed on November 19, 1999
6 that is entitled in part "Smart Cricket Repeaters in Drilling
7 Fluids for Wellbore Communications While Drilling Oil and Gas
8 Wells", an entire copy of which is incorporated herein by
9 reference.

10
11 This application further relates to disclosure in U.S.
12 Disclosure Document No. 474370 filed on May 16, 2000 that is
13 entitled in part "Casing Drilling with Standard MWD/LWD
14Having Releasable Standard Sized Drill Bit", an entire
15 copy of which is incorporated herein by reference.

16
17 This application further relates to disclosure in U.S.
18 Disclosure Document No. 475584 filed on June 13, 2000 that is
19 entitled in part "Lower Portion of Standard LWD/MWD Rotary
20 Drill String with Rotary Steering System and Rotary Drill Bit
21 Latched into ID of Larger Casing Having Undercutter to Drill
22 Oil and Gas Wells Whereby the Lower Portion is Retrieved upon
23 Completion of the Wellbore", an entire copy of which is
24 incorporated herein by reference.

25
26 This application further relates to disclosure in U.S.
27 Disclosure Document No. 521399 filed on November 12, 2002
28 that is entitled in part "Additional Methods and Apparatus
29 for Cementing Drill Strings in Place for One Pass Drilling
30 and Completion of Oil and Gas Wells", an entire copy of which
31 is incorporated herein by reference.

32
33 This application further relates to disclosure in U.S.
34 Disclosure Document No. 521690 filed on November 14, 2002

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1 that is entitled in part "More Methods and Apparatus for
2 Cementing Drill Strings in Place for One Pass Drilling and
3 Completion of Oil and Gas Wells", an entire copy of which is
4 incorporated herein by reference.

5
6 This application further relates to disclosure in U.S.
7 Disclosure Document No. 522547 filed on December 5, 2002 that
8 is entitled in part "Pump Down Cement Float Valve Needing No
9 Special Apparatus Within the Casing for Landing the Cement
10 Float Valve", an entire copy of which is incorporated herein
11 by reference.

12
13 Various references are referred to in the above defined
14 U.S. Disclosure Documents. For the purposes herein, the term
15 "reference cited in applicant's U.S. Disclosure Documents"
16 shall mean those particular references that have been
17 explicitly listed and/or defined in any of applicant's above
18 listed U.S. Disclosure Documents and/or in the attachments
19 filed with those U.S. Disclosure Documents. Applicant
20 explicitly includes herein by reference entire copies of each
21 and every "reference cited in applicant's U.S. Disclosure
22 Documents". In particular, applicant includes herein by
23 reference entire copies of each and every U.S. Patent cited
24 in U.S. Disclosure Document No. 452648, including all its
25 attachments, that was filed on March 5, 1999. To best
26 knowledge of applicant, all copies of U.S. Patents that were
27 ordered from commercial sources that were specified in the
28 U.S. Disclosure Documents are in the possession of applicant
29 at the time of the filing of the application herein.

30
31 Applications for U.S. Trademarks have been filed in the
32 USPTO for several terms used in this application.
33 An application for the Trademark "Smart Shuttle™" was filed
34 on February 14, 2001 that is Serial No. 76/213676, an entire

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1 copy of which is incorporated herein by reference. The
2 "Smart Shuttle™" is also called the "Well Locomotive™". An
3 application for the Trademark "Well Locomotive™" was filed on
4 February 20, 2001 that is Serial Number 76/218211, an entire
5 copy of which is incorporated herein by reference. An
6 application for the Trademark of "Downhole Rig" was filed on
7 June 11, 2001 that is Serial Number 76/274726, an entire copy
8 of which is incorporated herein by reference. An application
9 for the Trademark "Universal Completion Device™" was filed on
10 July 24, 2001 that is Serial Number 76/293175, an entire copy
11 of which is incorporated herein by reference. An application
12 for the Trademark "Downhole BOP" was filed on August 17, 2001
13 that is Serial Number 76/305201, an entire copy of which is
14 incorporated herein by reference.

15
16 Accordingly, in view of the Trademark Applications, the
17 term "smart shuttle" will be capitalized as "Smart Shuttle";
18 the term "well locomotive" will be capitalized as "Well
19 Locomotive"; the term "universal completion device" will be
20 capitalized as "Universal Completion Device"; and the term
21 "downhole bop" will be capitalized as "Downhole BOP".

22 23 24 BACKGROUND OF THE INVENTION

25 26 27 1. Field of Invention

28
29 The fundamental field of the invention relates
30 to apparatus and methods of operation that substantially
31 reduce the number of steps and the complexity to drill and
32 complete oil and gas wells. Because of the extraordinary
33 breadth of the fundamental field of the invention, there
34 are many related separate fields of the invention.

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1 Accordingly, the field of invention relates to apparatus
2 that uses the steel drill string attached to a drilling bit
3 during drilling operations used to drill oil and gas wells
4 for a second purpose as the casing that is cemented in place
5 during typical oil and gas well completions. The field of
6 invention further relates to methods of operation of
7 apparatus that provides for the efficient installation of a
8 cemented steel cased well during one single pass down into
9 the earth of the steel drill string. The field of invention
10 further relates to methods of operation of the apparatus that
11 uses the typical mud passages already present in a typical
12 drill bit, including any watercourses in a "regular bit", or
13 mud jets in a "jet bit", that allow mud to circulate during
14 typical drilling operations for the second independent, and
15 the distinctly separate, purpose of passing cement into the
16 annulus between the casing and the well while cementing the
17 drill string into place during one single drilling pass into
18 the earth. The field of invention further relates to
19 apparatus and methods of operation that provides the pumping
20 of cement down the drill string, through the mud passages in
21 the drill bit, and into the annulus between the formation
22 and the drill string for the purpose of cementing the drill
23 string and the drill bit into place during one single
24 drilling pass into the formation. The field of invention
25 further relates to a one-way cement valve and related devices
26 installed near the drill bit of the drill string that allows
27 the cement to set up efficiently while the drill string and
28 drill bit are cemented into place during one single drilling
29 pass into the formation.

30
31 The field of invention further relates to the use of a
32 slurry material instead of cement to complete wells during
33 the one pass drilling of oil and gas wells, where the term
34 "slurry material" may be any one, or more, of at least the

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1 following substances: cement, gravel, water, "cement
2 clinker", a "cement and copolymer mixture", a "blast furnace
3 slag mixture", and/or any mixture thereof; or any known
4 substance that flows under sufficient pressure. The field of
5 invention further relates to the use of slurry materials for
6 the following type of generic well completions: open-hole
7 well completions; typical cemented well completions having
8 perforated casings; gravel well completions having perforated
9 casings; and for any other related well completions. The
10 field of invention also relates to using slurry materials to
11 complete extended reach wellbores and extended reach lateral
12 wellbores. The field of invention also relates to using
13 slurry materials to complete extended reach wellbores and
14 extended reach lateral wellbores from offshore platforms.

15
16 The field of the invention further relates to the use of
17 retrievable instrumentation packages to perform LWD/MWD
18 logging and directional drilling functions while the well is
19 being drilled, which are particularly useful for the one pass
20 drilling of oil and gas wells, and which are also useful for
21 standard well completions, and which can also be retrieved
22 by a wireline attached to a Smart Shuttle having retrieval
23 apparatus or by other different retrieval means. The field
24 of the invention further relates to the use of Smart Shuttles
25 having retrieval apparatus that are capable of deploying and
26 installing into pipes smart completion devices that are used
27 to automatically complete oil and gas wells after the pipes
28 are disposed in the wellbore, which are useful for one pass
29 drilling and for standard cased well completions, and these
30 pipes include the following: a drill pipe, a drill string, a
31 casing, a casing string, tubing, a liner, a liner string, a
32 steel pipe, a metallic pipe, or any other pipe used for the
33 completion of oil and gas wells. The field of the invention
34 further relates to Smart Shuttles that use internal pump

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1 means to pump fluid from below the Smart Shuttle, to above
2 it, to cause the Smart Shuttle to move within the pipe to
3 conveniently install smart completion devices.
4

5 The field of invention disclosed herein also relates
6 to using progressive cavity pumps and electrical submersible
7 motors to make Smart Shuttles. The field of invention
8 further relates to closed-loop systems used to complete oil
9 and gas wells, where the term "to complete a well" means
10 "to finish work on a well and bring it into productive
11 status". In this field of the invention, a closed-loop
12 system to complete an oil and gas well is an automated system
13 under computer control that executes a sequence of programmed
14 steps, but those steps depend in part upon information
15 obtained from at least one downhole sensor that is
16 communicated to the surface to optimize and/or change the
17 steps executed by the computer to complete the well.
18

19 The field of invention further relates to a closed-loop
20 system that executes the steps during at least one
21 significant portion of the well completion process and the
22 completed well is comprised of at least a borehole in a
23 geological formation surrounding a pipe located within
24 the borehole, and this pipe may be any one of the following:
25 a metallic pipe; a casing string; a casing string with any
26 retrievable drill bit removed from the wellbore; a casing
27 string with any drilling apparatus removed from the wellbore;
28 a casing string with any electrically operated drilling
29 apparatus retrieved from the wellbore; a casing string with
30 any bicenter bit removed from the wellbore; a steel pipe; an
31 expandable pipe; an expandable pipe made from any material;
32 an expandable metallic pipe; an expandable metallic pipe with
33 any retrievable drill bit removed from the wellbore; an
34 expandable metallic pipe with any drilling apparatus removed

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1 from the wellbore; an expandable metallic pipe with any
2 electrically operated drilling apparatus retrieved from the
3 wellbore; an expandable metallic pipe with any bicenter bit
4 removed from the wellbore; a plastic pipe; a fiberglass pipe;
5 any type of composite pipe; any composite pipe that
6 encapsulates insulated wires carrying electricity and/or any
7 tubes containing hydraulic fluid; a composite pipe with any
8 retrievable drill bit removed from the wellbore; a composite
9 pipe with any drilling apparatus removed from the wellbore;
10 a composite pipe with any electrically operated drilling
11 apparatus retrieved from the wellbore; a composite pipe with
12 any bicenter bit removed from the wellbore; a drill string;
13 a drill string possessing a drill bit that remains attached
14 to the end of the drill string after completing the wellbore;
15 a drill string with any retrievable drill bit removed from
16 the wellbore; a drill string with any drilling apparatus
17 removed from the wellbore; a drill string with any
18 electrically operated drilling apparatus retrieved from the
19 wellbore; a drill string with any bicenter bit removed from
20 the wellbore; a coiled tubing; a coiled tubing possessing a
21 mud-motor drilling apparatus that remains attached to the
22 coiled tubing after completing the wellbore; a coiled tubing
23 left in place after any mud-motor drilling apparatus has been
24 removed; a coiled tubing left in place after any electrically
25 operated drilling apparatus has been retrieved from the
26 wellbore; a liner made from any material; a liner with any
27 retrievable drill bit removed from the wellbore; a liner with
28 any liner drilling apparatus removed from the wellbore;
29 a liner with any electrically operated drilling apparatus
30 retrieved from the liner; a liner with any bicenter bit
31 removed from the wellbore; any other pipe made of any
32 material with any type of drilling apparatus removed from the
33 pipe; or any other pipe made of any material with any type of
34 drilling apparatus removed from the wellbore.

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1 The field of invention further relates to a closed-loop
2 system that executes the steps during at least one
3 significant portion of the well completion process and the
4 completed well is comprised of at least a borehole in a
5 geological formation surrounding a pipe that may be accessed
6 through other pipes including surface pipes, production
7 lines, subsea production lines, etc.

8
9 Following the closed-loop well completion, the field of
10 invention further relates to using well completion apparatus
11 to monitor and/or control the production of hydrocarbons from
12 within the wellbore.

13
14 The field of invention also relates to closed-loop
15 systems to complete oil and gas wells that are useful for the
16 one pass drilling and completion of oil and gas wells.

17
18 The field of the invention further relates to the
19 closed-loop control of a tractor deployer that may also be
20 used to complete an oil and gas well.

21
22 The invention further relates to the tractor deployer
23 that is used to complete a well, perform production and
24 maintenance services on a well, and to perform enhanced
25 recovery services on a well.

26
27 The invention further relates to the tractor deployer
28 that is connected to surface instrumentation by a
29 substantially neutrally buoyant umbilical made from composite
30 materials.

31
32 Yet further, the field of invention also relates to a
33 method of drilling and completing a wellbore in a geological
34 formation to produce hydrocarbons from a well comprising at

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1 least the following four steps: drilling the well with a
2 retrievable drill bit attached to a casing; removing the
3 retrievable drill bit from the casing; pumping down a
4 one-way valve into the casing with a well fluid; and using
5 the one-way valve to cement the casing into the wellbore.
6

7 And finally, the field of invention relates to drilling
8 and completing wellbores in geological formations with
9 different types of pipes having a variety of retrievable
10 drill bits that are completed with pump-down one-way valves.
11
12

13 2. Description of the Prior Art 14

15 From an historical perspective, completing oil and gas
16 wells using rotary drilling techniques has in recent times
17 comprised the following typical steps. With a pile driver or
18 rotary rig, install any necessary conductor pipe on the
19 surface for attachment of the blowout preventer and for
20 mechanical support at the wellhead. Install and cement into
21 place any surface casing necessary to prevent washouts and
22 cave-ins near the surface, and to prevent the contamination
23 of freshwater sands as directed by state and federal
24 regulations. Choose the dimensions of the drill bit to
25 result in the desired sized production well. Begin rotary
26 drilling of the production well with a first drill bit.
27 Simultaneously circulate drilling mud into the well while
28 drilling. Drilling mud is circulated downhole to carry rock
29 chips to the surface, to prevent blowouts, to prevent
30 excessive mud loss into formation, to cool the bit, and to
31 clean the bit. After the first bit wears out, pull the drill
32 string out, change bits, lower the drill string into the well
33 and continue drilling. It should be noted here that each
34 "trip" of the drill bit typically requires many hours of rig

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1 time to accomplish the disassembly and reassembly of the
2 drill string, pipe segment by pipe segment.

3
4 Drill the production well using a succession of rotary
5 drill bits attached to the drill string until the hole is
6 drilled to its final depth. After the final depth is
7 reached, pull out the drill string and its attached drill
8 bit. Assemble and lower the production casing into the well
9 while back filling each section of casing with mud as it
10 enters the well to overcome the buoyancy effects of the air
11 filled casing (caused by the presence of the float collar
12 valve), to help avoid sticking problems with the casing, and
13 to prevent the possible collapse of the casing due to
14 accumulated build-up of hydrostatic pressure.

15
16 To "cure the cement under ambient hydrostatic
17 conditions", typically execute a two plug cementing procedure
18 involving a first Bottom Wiper Plug before and a second Top
19 Wiper Plug behind the cement that also minimizes cement
20 contamination problems comprised of the following individual
21 steps. Introduce the Bottom Wiper Plug into the interior of
22 the steel casing assembled in the well and pump down with
23 cement that cleans the mud off the walls and separates the
24 mud and cement. Introduce the Top Wiper Plug into the
25 interior of the steel casing assembled into the well and pump
26 down with water under pump pressure thereby forcing the
27 cement through the float collar valve and any other one-way
28 valves present. Allow the cement to cure.

30 31 SUMMARY OF THE INVENTION

32
33 The present invention allows for cementation of a drill
34 string with attached drill bit into place during one single

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1 drilling pass into a geological formation. The process of
2 drilling the well and installing the casing becomes one
3 single process that saves installation time and reduces costs
4 during oil and gas well completion procedures. Apparatus and
5 methods of operation of the apparatus are disclosed that use
6 the typical mud passages already present in a typical rotary
7 drill bit, including any watercourses in a "regular bit", or
8 mud jets in a "jet bit", for the second independent purpose
9 of passing cement into the annulus between the casing and the
10 well while cementing the drill string in place. This is a
11 crucial step that allows a "Typical Drilling Process"
12 involving some 14 steps to be compressed into the "New
13 Drilling Process" that involves only 7 separate steps as
14 described in the Description of the Preferred Embodiments
15 below. The New Drilling Process is now possible because of
16 "Several Recent Changes in the Industry" also described in
17 the Description of the Preferred Embodiments below. In
18 addition, the New Drilling Process also requires new
19 apparatus to properly allow the cement to cure under ambient
20 hydrostatic conditions. That new apparatus includes a
21 Latching Subassembly, a Latching Float Collar Valve Assembly,
22 the Bottom Wiper Plug, and the Top Wiper Plug. Suitable
23 methods of operation are disclosed for the use of the new
24 apparatus.

25
26 Suitable apparatus and methods of operation are
27 disclosed for drilling the wellbore with a rotary drill bit
28 attached to a drill string, which possesses a stabilizer,
29 that is cemented in place as the well casing by using a
30 one-way cement valve during one drilling pass into a
31 geological formation. Suitable apparatus and methods of
32 operation are disclosed for drilling the wellbore with a
33 rotary drill bit attached to a drill string, which possesses
34 a stabilizer, which is also used to centralize the drill

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1 string in the well during cementing operations. Suitable
2 apparatus and methods of operation are also disclosed for
3 drilling the wellbore with a rotary drill bit attached to a
4 casing string, which possesses a stabilizer, that is also
5 used to centralize the drill string in the well. A method is
6 also provided for drilling and lining a wellbore comprising:
7 drilling the wellbore using a drill string, the drill string
8 having an earth removal member operatively connected thereto
9 and a casing portion for lining the wellbore; stabilizing the
10 drill string while drilling the wellbore; locating the casing
11 portion within the wellbore; and maintaining the casing
12 portion in a substantially centralized position in relation
13 to a diameter of the wellbore.

14
15 Suitable methods and apparatus are disclosed for
16 drilling the wellbore with a rotary drill bit attached to a
17 drill string, which possesses a directional drilling means,
18 that is cemented in place as the well casing by using a
19 one-way cement valve during one drilling pass into a
20 geological formation. Suitable methods and apparatus are
21 also disclosed for drilling the wellbore with a rotary drill
22 bit attached to a drill string that has means for selectively
23 causing a drilling trajectory to change during drilling.
24 A method is also provided for drilling and lining a wellbore
25 comprising: drilling the wellbore using a drill string, the
26 drill string having an earth removal member operatively
27 connected thereto and a casing portion for lining the
28 wellbore; selectively causing a drilling trajectory to change
29 during the drilling; and lining the wellbore with the casing
30 portion.

31
32 Suitable methods and apparatus are disclosed for
33 drilling the wellbore with a rotary drill bit attached to a
34 drill string, which possesses a geophysical parameter sensing

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1 member, that is cemented in place as the well casing by using
2 a one-way cement valve during one drilling pass into a
3 geological formation. Suitable methods and apparatus are
4 also disclosed for drilling the wellbore with a rotary drill
5 bit attached to a drill string that has at least one
6 geophysical parameter sensing member to measure at least one
7 geophysical quantity from within the drill string. Apparatus
8 is also provided for drilling a wellbore comprising: a drill
9 string having a casing portion for lining the wellbore; and
10 a drilling assembly operatively connected to the drill string
11 and having an earth removal member and a geophysical
12 parameter sensing member.
13

14 Suitable methods and apparatus are provided for drilling
15 the wellbore with a rotary drill bit attached to a drill
16 string that is encapsulated in place with a physically
17 alterable bonding material as the well casing by using a
18 one-way valve during one drilling pass into a geological
19 formation. Suitable methods and apparatus are also provided
20 for drilling the wellbore with a rotary drill bit attached to
21 a drill string that is encapsulated with a physically
22 alterable bonding material that is allowed to cure in the
23 wellbore to make a cased wellbore. A method is also provided
24 for lining a wellbore with a tubular comprising: drilling the
25 wellbore using a drill string, the drill string having a
26 casing portion; locating the casing portion within the
27 wellbore; placing a physically alterable bonding material in
28 an annulus formed between the casing portion and the
29 wellbore; establishing a hydrostatic pressure condition in
30 the wellbore; and allowing the bonding material to physically
31 alter under the hydrostatic pressure condition.
32

33 Suitable methods and apparatus are provided for drilling
34 the wellbore with a drill string having a rotary drill bit

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1 attached to a drilling assembly which has a portion that is
2 selectively removable from the wellbore before the drill
3 string is cemented into place by using a one-way valve during
4 one pass drilling into a geological formation. Suitable
5 methods and apparatus are provided for drilling the wellbore
6 with a drill string having a rotary drill bit attached to a
7 drilling assembly which has a portion that is selectively
8 removable from the wellbore before the drill string is
9 cemented into place as the well casing. An apparatus is also
10 provided for drilling a wellbore comprising: a drill string
11 having a casing portion for lining the wellbore; and a
12 drilling assembly operatively connected to the drill string
13 and having an earth removal member; a portion of the drilling
14 assembly being selectively removable from the wellbore
15 without removing the casing portion.

16
17 Suitable methods and apparatus are provided for drilling
18 the wellbore from an offshore platform with a rotary drill
19 bit attached to a drill string and then cementing that drill
20 string into place by using a one-way valve during one
21 drilling pass into a geological formation. Suitable methods
22 and apparatus are also provided for drilling the wellbore
23 from an offshore platform with a rotary drill bit attached to
24 a drill string which may be cemented into place or which may
25 be retrieved from the wellbore prior to cementing operations.
26 A method is also provided for drilling a borehole into a
27 geological formation from an offshore platform using casing
28 as at least a portion of the drill string and completing the
29 well with the casing during one single drilling pass into the
30 geological formation.

31
32 Methods are further disclosed wherein different types of
33 slurry materials are used for well completion that include at
34 least cement, gravel, water, a "cement clinker", and any

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1 "blast furnace slag mixture". Methods are further disclosed
2 using a slurry material to complete wells including at least
3 the following: open-hole well completions; cemented well
4 completions having a perforated casing; gravel well
5 completions having perforated casings; extended reach
6 wellbores; extended reach lateral wellbores; and extended
7 reach lateral wellbores completed from offshore drilling
8 platforms.
9

10 Involving the one pass drilling and completion of
11 wellbores that is also useful for other well completion
12 purposes, the present invention includes Smart Shuttles which
13 are used to complete the oil and gas wells. Following
14 drilling operations into a geological formation, a steel pipe
15 is disposed in the wellbore. In the following, any pipe may
16 be used, but an example of steel pipe is used in the
17 following examples for the purposes of simplicity only. The
18 steel pipe may be a standard casing installed into the
19 wellbore using typical industry practices. Alternatively,
20 the steel pipe may be a drill string attached to a rotary
21 drill bit that is to remain in the wellbore following
22 completion during so-called "one pass drilling operations".
23 Further, the steel pipe may be a drill pipe from which has
24 been removed a retrievable or retractable drill bit. Or, the
25 steel pipe may be a coiled tubing having a mud motor drilling
26 apparatus at its end. Using typical procedures in the
27 industry, the well is "completed" by placing into the steel
28 pipe various standard completion devices, some of which are
29 conveyed into place with the drilling rig. Here, instead,
30 Smart Shuttles are used to convey into the steel pipe various
31 smart completion devices used to complete the oil and gas
32 well. The Smart Shuttles are then used to install various
33 smart completion devices. And the Smart Shuttles may be used
34 to retrieve from the wellbore various smart completion

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1 devices. Smart Shuttles may be attached to a wireline,
2 coiled tubing, or to a wireline installed within coiled
3 tubing, and such applications are called "tethered Smart
4 Shuttles". Smart Shuttles may be robotically independent of
5 the wireline, etc., provided that large amounts of power are
6 not required for the completion device, and such devices are
7 called "untethered shuttles". The smart completion devices
8 are used in some cases to machine portions of the steel pipe.
9 Completion substances, such as cement, gravel, etc. are
10 introduced into the steel pipe using smart wiper plugs and
11 Smart Shuttles as required. Smart Shuttles may be
12 robotically and automatically controlled from the surface of
13 the earth under computer control so that the completion of a
14 particular oil and gas well proceeds automatically through a
15 progression of steps. A wireline attached to a Smart Shuttle
16 may be used to energize devices from the surface that consume
17 large amounts of power. Pressure control at the surface is
18 maintained by use of a suitable lubricator device that has
19 been modified to have a Smart Shuttle chamber suitably
20 accessible from the floor of the drilling rig. A particular
21 Smart Shuttle of interest is a wireline conveyed Smart
22 Shuttle that possesses an electrically operated internal pump
23 that pumps fluid from below the shuttle to above the shuttle
24 that causes the Smart Shuttle to pump itself down into the
25 well. Suitable valves that open allow for the retrieval of
26 the Smart Shuttle by pulling up on the wireline. Similar
27 comments apply to coiled tubing conveyed Smart Shuttles.
28 Using Smart Shuttles to complete oil and gas wells reduces
29 the amount of time the drilling rig is used for standard
30 completion purposes. The Smart Shuttles therefore allow the
31 use of the drilling rig for its basic purpose - the drilling
32 of oil and gas wells.

33
34
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1 The present invention further includes a closed-loop
2 system used to complete oil and gas wells. The term "to
3 complete a well" means "to finish work on a well and bring it
4 into productive status". A closed-loop system to complete an
5 oil and gas well is an automated system under computer
6 control that executes a sequence of programmed steps, but
7 those steps depend in part upon information obtained from at
8 least one downhole sensor that is communicated to the surface
9 to optimize and/or change the steps executed by the computer
10 to complete the well. The closed-loop system executes the
11 steps during at least one significant portion of the well
12 completion process. A type of Smart Shuttle comprised of a
13 progressive cavity pump and an electrical submersible motor
14 is particularly useful for such closed-loop systems. The
15 completed well is comprised of at least a borehole in a
16 geological formation surrounding a pipe located within the
17 borehole. The pipe may be a metallic pipe; a casing string;
18 a casing string with any retrievable drill bit removed from
19 the wellbore; a steel pipe; a drill string; a drill string
20 possessing a drill bit that remains attached to the end of
21 the drill string after completing the wellbore; a drill
22 string with any retrievable drill bit removed from the
23 wellbore; a coiled tubing; a coiled tubing possessing a
24 mud-motor drilling apparatus that remains attached to the
25 coiled tubing after completing the wellbore; or a liner.
26 Following the closed-loop well completion, apparatus
27 monitoring the production of hydrocarbons from within
28 the wellbore may be used to control the production of
29 hydrocarbons from the wellbore. The closed-loop completion
30 of oil and gas wells provides apparatus and methods of
31 operation to substantially reduce the number of steps, the
32 complexity, and the cost to complete oil and gas wells.

33
34
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1 Accordingly, the closed-loop completion of oil and gas
2 wells is a substantial improvement over present technology
3 in the oil and gas industries.
4

5 The closed-loop control of a tractor deployer may also
6 be used to complete an oil and gas well. Tractor deployer is
7 used to complete a well, perform production and maintenance
8 services on a well, and to perform enhanced recovery services
9 on a well. The well servicing tractor deployer may be
10 connected to surface instrumentation by a neutrally buoyant
11 umbilical. Some of these umbilicals are made from
12 composite materials.
13

14 Disclosure is provided of a method of drilling and
15 completing a wellbore in a geological formation to produce
16 hydrocarbons from a well comprising at least the following
17 four steps: drilling the well with a retrievable drill bit
18 attached to a casing; removing the retrievable drill bit from
19 the casing; pumping down a one-way valve into the casing with
20 a well fluid; and using the one-way valve to cement the
21 casing into the wellbore.
22

23 Additional disclosure is provided that relates to
24 drilling and completing wellbores in geological formations
25 with different types of pipes having a variety of retrievable
26 drill bits that are completed with pump-down cement one-way
27 valves.
28

29 BRIEF DESCRIPTION OF THE DRAWINGS

30
31
32 Figure 1 shows a section view of a rotary drill string
33 having a rotary drill bit in the process of being cemented in
34 place during one drilling pass into formation by using a

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1 Latching Float Collar Valve Assembly that has been pumped
2 into place above the rotary drill bit that is a preferred
3 embodiment of the invention, where the rotary drill bit is a
4 milled tooth rotary drill bit.

5
6 Figure 1A is substantially the same as Figure 1, except
7 that stabilizer ribs have been welded to the Latching Float
8 Collar Valve Assembly that also act as a centralizer, or
9 centralizer means.

10
11 Figure 1B shows an external view of Figure 1A that shows
12 three stabilizer ribs welded to the Latching Float Collar
13 Valve Assembly, and the milled tooth rotary drill bit
14 in Figure 1A has been replaced with a jet bit.

15
16 Figure 1C is substantially similar to Figure 1B, except
17 here three stabilizer ribs have been welded to a bottomhole
18 assembly ("BHA"), and the jet bit in Figure 1B has been
19 replaced with a jet deflection roller cone bit.

20
21 Figure 1D shows three stabilizer ribs welded to a length
22 of casing, and these ribs also act as a centralizer, or
23 centralizer means.

24
25 Figure 1E shows a jet deflection bit attached to an
26 angle-building bottomhole assembly having stabilizer
27 ribs which are attached to a drill string.

28
29 Figure 1F shows the fluid passageways in a jet bit.

30
31 Figure 2 shows a section view of a rotary drill string
32 having a rotary drill bit in the process of being cemented
33 into place during one drilling pass into formation by using a
34 Permanently Installed Float Collar Valve Assembly that is

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1 permanently installed above the rotary drill bit that is a
2 preferred embodiment of the invention.

3
4 Figure 3 shows a section view of a tubing conveyed mud
5 motor drilling apparatus in the process of being cemented
6 into place during one drilling pass into formation by using a
7 Latching Float Collar Valve Assembly that has been pumped
8 into place above the mud motor assembly that is a preferred
9 embodiment of the invention.

10
11 Figure 4 shows a section view of a tubing conveyed mud
12 motor drilling apparatus that in addition has several wiper
13 plugs in the process of sequentially completing the well with
14 gravel and then with cement during the one pass drilling and
15 completion of the wellbore.

16
17 Figure 5 shows a section view of an apparatus for the
18 one pass drilling and completion of extended reach lateral
19 wellbores with a drill bit attached to a rotary drill string
20 to produce hydrocarbons from offshore platforms.

21
22 Figure 6 shows a section view of an embodiment of the
23 invention that is particularly configured so that
24 Measurement-While-Drilling (MWD) and Logging-While-Drilling
25 (LWD) can be done during rotary drilling operations with a
26 Retrievable Instrumentation Package installed in place within
27 a Smart Drilling and Completion Sub near the drill bit
28 which is useful for the one pass drilling and completion
29 of wellbores and which is also useful for standard well
30 drilling procedures.

31
32 Figure 7 shows a section view of the Retrievable
33 Instrumentation Package and the Smart Drilling and Completion
34 Sub that also has directional drilling control apparatus and

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1 instrumentation which is useful for the one pass drilling and
2 completion of wellbores and which is also useful for standard
3 well drilling operations.

4
5 Figure 8 shows a section view of the wellhead, the Wiper
6 Plug Pump-Down Stack, the Smart Shuttle Chamber, the Wireline
7 Lubricator System, the Smart Shuttle and the Retrieval Sub
8 suspended by the wireline which is useful for the one pass
9 drilling and completion of wellbores, and which is also
10 useful for the completion of wells using cased well
11 completion procedures.

12
13 Figure 9 shows a section view in detail of the Smart
14 Shuttle and the Retrieval Sub while located in the Smart
15 Shuttle Chamber.

16
17 Figure 10 shows a section view of the Smart Shuttle and
18 the Retrieval Sub in a position where the elastomer sealing
19 elements of the Smart Shuttle have sealed against the
20 interior of the pipe, and the internal pump of the Smart
21 Shuttle is ready to pump fluid volumes ΔV_1 from below the
22 Smart Shuttle to above it so that the Smart Shuttle
23 translates downhole.

24
25 Figure 11 is a generalized block diagram of one
26 embodiment of a Smart Shuttle having a first electrically
27 operated positive displacement pump and a second electrically
28 operated pump.

29
30 Figure 12 shows a block diagram of a pump transmission
31 device that prevents pump stalling, and other pump problems,
32 by matching the load seen by the pump to the power available
33 from the motor within the Smart Shuttle.

34
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1 Figure 13 shows a block diagram of preferred embodiment
2 of a Smart Shuttle having a hybrid pump design that also
3 provides for a turbine assembly that causes a traction
4 wheel to engage the casing to cause translation of the
5 Smart Shuttle.
6

7 Figure 14 shows a block diagram of the computer control
8 of the wireline drum and the Smart Shuttle in a preferred
9 embodiment of the invention that allows the system to
10 be operated as an Automated Smart Shuttle System, or
11 "closed-loop completion system", that is useful for the
12 closed-loop completion of one pass drilling operations,
13 and that is also useful for completion operations within
14 a standard casing string.
15

16 Figure 15 shows a section view of a rubber-type material
17 wiper plug that can be attached to the Retrieval Sub and
18 placed into the Wiper Plug Pump-Down Stack and subsequently
19 used for the well completion process.
20

21 Figure 16 shows a section view of the Casing Saw that
22 can be attached to the Retrieval Sub and conveyed downhole
23 with the Smart Shuttle.
24

25 Figure 17 shows a section view of the wellhead, the
26 Wiper Plug Pump-Down Stack, the Smart Shuttle Chamber, the
27 Coiled Tubing Lubricator System, and the pump-down single
28 zone packer apparatus suspended by the coiled tubing in the
29 well before commencing the final single-zone completion of
30 the well which in this case pertains to the one pass drilling
31 and completion of wellbores, but that is also useful for
32 standard cased well completions.
33
34

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1 Figure 17A shows an expanded view of the pump-down
2 single zone packer apparatus that is shown in Figure 17.
3

4 Figure 18 shows a "pipe means" deployed in the wellbore
5 that may be a pipe made of any material, a metallic pipe, a
6 steel pipe, a composite pipe, a drill pipe, a drill string, a
7 casing, a casing string, a liner, a liner string, tubing, or
8 a tubing string, or any means to convey oil and gas to the
9 surface for production that may be completed using a Smart
10 Shuttle, Retrieval Sub, and Smart Completion Devices. The
11 "pipe means" is explicitly shown here so that it is crystal
12 clear that various preferred embodiments cited above for use
13 during the one pass drilling and completion of oil and gas
14 wells can in addition also be used in standard well drilling
15 and casing operations.
16

17 Figure 18A shows a modified and expanded form of
18 Figure 18 wherein the last portion of the "pipe means" has
19 "pipe mounted latching means" that may be used for a number
20 of purposes including attaching a retrievable drill bit
21 and/or as a positive "stop" for a pump-down one-way valve
22 means following the retrieval of the retrievable drill
23 bit during one pass drilling and completion operations.
24

25 Figure 18B shows a pump-down one-way valve means
26 disposed within a pipe following the removal of a
27 retrievable, or retractable, drill bit from the pipe. The
28 pump-down one-way valve means is also called a cement float
29 valve, or a one-way valve, for simplicity. One example of a
30 pipe is a casing.
31

32 Figure 18C shows a retrievable, or retractable, drilling
33 apparatus that possesses a retrievable, or retractable, drill
34

1 bit disposed in a pipe during drilling operations.
2 One example of a pipe is a casing.
3
4

5 DESCRIPTION OF THE PREFERRED EMBODIMENTS 6

7 In the following, Figure 1 is the same as Figure 1
8 originally filed with U.S. Patent Application Serial
9 No. 08/323,152, now U.S. Patent No. 5,551,521, except the
10 artwork involving the shape of the arrows and other minor
11 drafting details have been changed. In the following, the
12 figures are substantially the same which have been filed with
13 co-pending U.S. Patent Application Serial No. 10/189,570
14 except that Figures 1A, 1B, 1C, 1D, 1E, and 1F have been
15 added.
16

17 In relation to Figure 1, and to Figures 2-5, apparatus
18 and methods of operation of that apparatus are disclosed
19 herein in the preferred embodiments of the invention that
20 allow for cementation of a drill string with attached drill
21 bit into place during one single drilling pass into a
22 geological formation. The method of drilling the well and
23 installing the casing becomes one single process that saves
24 installation time and reduces costs during oil and gas well
25 completion procedures as documented in the following
26 description of the preferred embodiments of the invention.
27 Apparatus and methods of operation of the apparatus are
28 disclosed herein that use the typical mud passages already
29 present in a typical rotary drill bit, including any
30 watercourses in a "regular bit", or mud jets in a "jet bit",
31 for the second independent purpose of passing cement into the
32 annulus between the casing and the well while cementing the
33 drill string in place. Slurry materials may be used for
34 completion purposes in extended lateral wellbores.

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1 The following text is substantially quoted from U.S.
2 Patent Application Serial No. 08/323,152, now U.S. Patent
3 No. 5,551,521, as it relates to Figure 1. The following text
4 is also substantially quoted from U.S. Patent Application
5 Serial No. 09/295,808, now U.S. Patent No. 6,263,987 B1, as
6 it relates to Figures 2-5.

7
8 Figure 1 shows a section view of a drill string in the
9 process of being cemented in place during one drilling pass
10 into formation. A borehole 2 is drilled though the earth
11 including geological formation 4. The borehole is drilled
12 with a milled tooth rotary drill bit 6 having milled steel
13 roller cones 8, 10, and 12 (not shown for simplicity). A
14 standard water passage 14 is shown through the rotary cone
15 drill bit. This rotary bit could equally be a tungsten
16 carbide insert roller cone bit having jets for waterpassages,
17 the principle of operation and the related apparatus being
18 the same for either case for the preferred embodiment herein.

19
20 The threads 16 on rotary drill bit 6 are screwed into
21 the Latching Subassembly 18. The Latching Subassembly is
22 also called the Latching Sub for simplicity herein. The
23 Latching Sub is a relatively thick-walled steel pipe having
24 some functions similar to a standard drill collar.

25
26 The Latching Float Collar Valve Assembly 20 is pumped
27 downhole with drilling mud after the depth of the well is
28 reached. The Latching Float Collar Valve Assembly is pumped
29 downhole with mud pressure pushing against the Upper Seal 22
30 of the Latching Float Collar Valve Assembly. The Latching
31 Float Collar Valve Assembly latches into place into Latch
32 Recession 24. The Latch 26 of the Latching Float Collar
33 Valve Assembly is shown latched into place with Latching
34 Spring 28 pushing against Latching Mandrel 30. When the

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1 Latch 26 is properly seated into place within the Latch
2 Recession 24, the clearances and materials of the Latch and
3 mating Latch Recession are to be chosen such that very little
4 cement will leak through the region of the Latch Recession 24
5 of the Latching Subassembly 18 under any back-pressure
6 (upward pressure) in the well. Many means can be utilized to
7 accomplish this task, including fabricating the Latch 26 from
8 suitable rubber compounds, suitably designing the upper
9 portion of the Latching Float Collar Valve Assembly 20
10 immediately below the Upper Seal 22, the use of various
11 O-rings within or near Latch Recession 24, etc.
12

13 The Float 32 of the Latching Float Collar Valve Assembly
14 seats against the Float Seating Surface 34 under the force
15 from Float Collar Spring 36 that makes a one-way cement
16 valve. However, the pressure applied to the mud or cement
17 from the surface may force open the Float to allow mud or
18 cement to be forced into the annulus generally designated as
19 38 in Figure 1. This one-way cement valve is a particular
20 example of "a one-way cement valve means installed near the
21 drill bit" which is a term defined herein. The one-way
22 cement valve means may be installed at any distance from
23 the drill bit but is preferentially installed "near"
24 the drill bit.
25

26 Figure 1 corresponds to the situation where cement is in
27 the process of being forced from the surface through the
28 Latching Float Collar Valve Assembly. In fact, the top level
29 of cement in the well is designated as element 40. Below 40,
30 cement fills the annulus of the borehole. Above 40, mud
31 fills the annulus of the borehole. For example, cement is
32 present at position 42 and drilling mud is present at
33 position 44 in Figure 1.
34

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1 Relatively thin-wall casing, or drill pipe, designated
2 as element 46 in Figure 1, is attached to the Latching Sub.
3 The bottom male threads of the drill pipe 48 are screwed into
4 the female threads 50 of the Latching Sub.

5
6 The drilling mud was wiped off the walls of the drill
7 pipe in the well with Bottom Wiper Plug 52. The Bottom Wiper
8 Plug is fabricated from rubber in the shape shown. Portions
9 54 and 56 of the Upper Seal of the Bottom Wiper Plug are
10 shown in a ruptured condition in Figure 1. Initially, they
11 sealed the upper portion of the Bottom Wiper Plug. Under
12 pressure from cement, the Bottom Wiper Plug is pumped down
13 into the well until the Lower Lobe of the Bottom Wiper Plug
14 58 latches into place into Latching Sub Recession 60 in the
15 Latching Sub. After the Bottom Wiper Plug latches into
16 place, the pressure of the cement ruptures The Upper Seal
17 of the Bottom Wiper Plug. A Bottom Wiper Plug Lobe 62 is
18 shown in Figure 1. Such lobes provide an efficient means to
19 wipe the mud off the walls of the drill pipe while the Bottom
20 Wiper Plug is pumped downhole with cement.

21
22 Top Wiper Plug 64 is being pumped downhole by water 66
23 under pressure in the drill pipe. As the Top Wiper Plug 64
24 is pumped down under water pressure, the cement remaining in
25 region 68 is forced downward through the Bottom Wiper Plug,
26 through the Latching Float Collar Valve Assembly, through the
27 waterpassages of the drill bit and into the annulus in the
28 well. A Top Wiper Plug Lobe 70 is shown in Figure 1. Such
29 lobes provide an efficient means to wipe the cement off the
30 walls of the drill pipe while the Top Wiper Plug is pumped
31 downhole with water.

32
33 After the Bottom Surface 72 of the Top Wiper Plug is
34 forced into the Top Surface 74 of the Bottom Wiper Plug,

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1 almost the entire "cement charge" has been forced into the
2 annulus between the drill pipe and the hole. As pressure is
3 reduced on the water, the Float of the Latching Float Collar
4 Valve Assembly seals against the Float Seating Surface 34.
5 As the water pressure is reduced on the inside of the drill
6 pipe, then the cement in the annulus between the drill pipe
7 and the hole can cure under ambient hydrostatic conditions.
8 This procedure herein provides an example of the proper
9 operation of a "one-way cement valve means".

10
11 Therefore, the preferred embodiment in Figure 1 provides
12 apparatus that uses the steel drill string attached to a
13 drilling bit during drilling operations used to drill oil and
14 gas wells for a second purpose as the casing that is cemented
15 in place during typical oil and gas well completions.

16
17 The preferred embodiment in Figure 1 provides apparatus
18 and methods of operation of the apparatus that results in the
19 efficient installation of a cemented steel cased well
20 during one single pass down into the earth of the steel drill
21 string thereby making a steel cased borehole or cased well.

22
23 The steps described herein in relation to the preferred
24 embodiment in Figure 1 provide a method of operation that
25 uses the typical mud passages already present in a typical
26 rotary drill bit, including any watercourses in a "regular
27 bit", or mud jets in a "jet bit", that allow mud to circulate
28 during typical drilling operations for the second
29 independent, and the distinctly separate, purpose of passing
30 cement into the annulus between the casing and the well while
31 cementing the drill string into place during one single pass
32 into the earth.

33
34
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1 The preferred embodiment of the invention further
2 provides apparatus and methods of operation that results in
3 the pumping of cement down the drill string, through the mud
4 passages in the drill bit, and into the annulus between the
5 formation and the drill string for the purpose of cementing
6 the drill string and the drill bit into place during one
7 single drilling pass into the formation.

8
9 The apparatus described in the preferred embodiment in
10 Figure 1 also provide a one-way cement valve and related
11 devices installed near the drill bit of the drill string
12 that allows the cement to set up efficiently while the drill
13 string and drill bit are cemented into place during one
14 single drilling pass into the formation.

15
16 Methods of operation of apparatus disclosed in
17 Figure 1 have been disclosed that use the typical mud
18 passages already present in a typical rotary drill bit,
19 including any watercourses in a "regular bit", or mud jets in
20 a "jet bit", for the second independent purpose of passing
21 cement into the annulus between the casing and the well while
22 cementing the drill string in place. This is a crucial step
23 that allows a "Typical Drilling Process" involving some
24 14 steps to be compressed into the "New Drilling Process"
25 that involves only 7 separate steps as described in detail
26 below. The New Drilling Process is now possible because
27 of "Several Recent Changes in the Industry" also described
28 in detail below.

29
30 Typical procedures used in the oil and gas industries to
31 drill and complete wells are well documented. For example,
32 such procedures are documented in the entire "Rotary Drilling
33 Series" published by the Petroleum Extension Service of
34 The University of Texas at Austin, Austin, Texas that is

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1 incorporated herein by reference in its entirety comprised
2 of the following: Unit I - "The Rig and Its Maintenance"
3 (12 Lessons); Unit II - "Normal Drilling Operations"
4 (5 Lessons); Unit III - Nonroutine Rig Operations
5 (4 Lessons); Unit IV - Man Management and Rig Management
6 (1 Lesson); and Unit V - Offshore Technology (9 Lessons).
7 All of the individual Glossaries of all of the above Lessons
8 in their entirety are also explicitly incorporated herein,
9 and all definitions in those Glossaries shall be considered
10 to be explicitly referenced and/or defined herein.

11
12 Additional procedures used in the oil and gas industries
13 to drill and complete wells are well documented in the series
14 entitled "Lessons in Well Servicing and Workover" published
15 by the Petroleum Extension Service of The University of Texas
16 at Austin, Austin, Texas that is incorporated herein by
17 reference in its entirety comprised of all 12 Lessons.
18 All of the individual Glossaries of all of the above Lessons
19 in their entirety are also explicitly incorporated herein,
20 and any and all definitions in those Glossaries shall be
21 considered to be explicitly referenced and/or defined herein.

22
23 With reference to typical practices in the oil and gas
24 industries, a typical drilling process may therefore be
25 described in the following.

26 27 28 Typical Drilling Process

29
30 From an historical perspective, completing oil and gas
31 wells using rotary drilling techniques have in recent times
32 comprised the following typical steps:
33
34

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1 Step 1. With a pile driver or rotary rig, install
2 any necessary conductor pipe on the surface for attachment of
3 the blowout preventer and for mechanical support at the
4 wellhead.

5
6 Step 2. Install and cement into place any surface
7 casing necessary to prevent washouts and cave-ins near the
8 surface, and to prevent the contamination of freshwater sands
9 as directed by state and federal regulations.

10
11 Step 3. Choose the dimensions of the drill bit to
12 result in the desired sized production well. Begin rotary
13 drilling of the production well with a first drill bit.
14 Simultaneously circulate drilling mud into the well while
15 drilling. Drilling mud is circulated downhole to carry rock
16 chips to the surface, to prevent blowouts, to prevent
17 excessive mud loss into formation, to cool the bit, and to
18 clean the bit. After the first bit wears out, pull the drill
19 string out, change bits, lower the drill string into the well
20 and continue drilling. It should be noted here that each
21 "trip" of the drill bit typically requires many hours of rig
22 time to accomplish the disassembly and reassembly of the
23 drill string, pipe segment by pipe segment. Here, each pipe
24 segment may consist of several pipe joints.

25
26 Step 4. Drill the production well using a succession
27 of rotary drill bits attached to the drill string until the
28 hole is drilled to its final depth.

29
30 Step 5. After the final depth is reached, pull out
31 the drill string and its attached drill bit.

32
33 Step 6. Perform open-hole logging of the geological
34 formations to determine the quantitative amounts of oil and

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1 gas present. This typically involves making physical
2 measurements that are used to determine the porosity of the
3 rock, the electrical resistivity of the water present, the
4 electrical resistivity of the rock, the total amounts of oil
5 and gas present, the relative amounts of oil and gas present,
6 and the use of Archie's Equations (or their equivalent
7 representation, or their approximation by other algebraic
8 expressions, or their substitution for similar geophysical
9 analysis). Here, such open-hole physical measurements
10 include electrical measurements, inductive measurements,
11 acoustic measurements, natural gamma ray measurements,
12 neutron measurements, and other types of nuclear
13 measurements, etc. Such measurements may also be used to
14 determine the permeability of the rock. If no oil and gas is
15 present from the analysis of such open-hole logs, an option
16 can be chosen to cement the well shut. If commercial amounts
17 of oil and gas are present, continue the following steps.

18
19 Step 7. Typically reassemble the drill bit and the
20 drill string in the well to clean the well after open-hole
21 logging.

22
23 Step 8. Pull out the drill string and its attached
24 drill bit.

25
26 Step 9. Attach the casing shoe into the bottom male
27 pipe threads of the first length of casing to be installed
28 into the well. This casing shoe may or may not have a
29 one-way valve ("casing shoe valve") installed in its interior
30 to prevent fluids from back-flowing from the well into the
31 casing string.

32
33 Step 10. Typically install the float collar onto the
34 top female threads of the first length of casing to be

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1 installed into the well which has a one-way valve ("float
2 collar valve") that allows the mud and cement to pass only
3 one way down into the hole thereby preventing any fluids from
4 back-flowing from the well into the casing string.
5 Therefore, a typical installation has a casing shoe attached
6 to the bottom and the float collar valve attached to the top
7 portion of the first length of casing to be lowered into the
8 well. The float collar and the casing shoe are often
9 installed into one assembly for convenience that entirely
10 replace this first length of casing. Please refer to the
11 book entitled "Casing and Cementing", Unit II, Lesson 4,
12 Second Edition, of the Rotary Drilling Series, Petroleum
13 Extension Service, The University of Texas at Austin, Austin,
14 Texas, 1982 (hereinafter defined as "Ref.1"), an entire copy
15 of which is incorporated herein by reference. In particular,
16 please refer to pages 28-35 of that book (Ref. 1). All of
17 the individual definitions of words and phrases in the
18 Glossary of Ref. 1 are also explicitly and separately
19 incorporated herein in their entirety by reference.

20
21 Step 11. Assemble and lower the production casing into
22 the well while back filling each section of casing with mud
23 as it enters the well to overcome the buoyancy effects of the
24 air filled casing (caused by the presence of the float collar
25 valve), to help avoid sticking problems with the casing, and
26 to prevent the possible collapse of the casing due to
27 accumulated build-up of hydrostatic pressure.

28
29 Step 12. To "cure the cement under ambient hydrostatic
30 conditions", typically execute a two-plug cementing procedure
31 involving a first Bottom Wiper Plug before and a second Top
32 Wiper Plug behind the cement that also minimizes cement
33 contamination problems comprised of the following individual
34 steps:

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1 A. Introduce the Bottom Wiper Plug into the
2 interior of the steel casing assembled in the well and pump
3 down with cement that cleans the mud off the walls and
4 separates the mud and cement (Ref. 1, pages 28-35).

5
6 B. Introduce the Top Wiper Plug into the interior
7 of the steel casing assembled into the well and pump down
8 with water under pump pressure thereby forcing the cement
9 through the float collar valve and any other one-way valves
10 present (Ref. 1, pages 28-35).

11
12 C. After the Bottom Wiper Plug and the Top Wiper
13 Plug have seated in the float collar, release the pump
14 pressure on the water column in the casing that results in
15 the closing of the float collar valve which in turn prevents
16 cement from backing up into the interior of the casing. The
17 resulting interior pressure release on the inside of the
18 casing upon closure of the float collar valve prevents
19 distortions of the casing that might prevent a good cement
20 seal (Ref. 1, page 30). In such circumstances, "the cement
21 is cured under ambient hydrostatic conditions".

22
23 Step 13. Allow the cement to cure.

24
25 Step 14. Follow normal "final completion operations"
26 that include installing the tubing with packers and
27 perforating the casing near the producing zones. For a
28 description of such normal final completion operations,
29 please refer to the book entitled "Well Completion Methods",
30 Well Servicing and Workover, Lesson 4, from the series
31 entitled "Lessons in Well Servicing and Workover", Petroleum
32 Extension Service, The University of Texas at Austin, Austin,
33 Texas, 1971 (hereinafter defined as "Ref. 2"), an entire
34 copy of which is incorporated herein by reference. All of

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1 the individual definitions of words and phrases in the
2 Glossary of Ref. 2 are also explicitly and separately
3 incorporated herein in their entirety by reference. Other
4 methods of completing the well are described therein that
5 shall, for the purposes of this application herein, also be
6 called "final completion operations".
7
8

9 Several Recent Changes in the Industry

10
11 Several recent concurrent changes in the industry have
12 made it possible to reduce the number of steps defined above.
13 These changes include the following:
14

15 a. Until recently, drill bits typically wore out during
16 drilling operations before the desired depth was reached by
17 the production well. However, certain drill bits have
18 recently been able to drill a hole without having to be
19 changed. For example, please refer to the book entitled
20 "The Bit", Unit I, Lesson 2, Third Edition, of the Rotary
21 Drilling Series, The University of Texas at Austin, Austin,
22 Texas, 1981 (hereinafter defined as "Ref. 3"), an entire copy
23 of which is incorporated herein by reference. All of the
24 individual definitions of words and phrases in the Glossary
25 of Ref. 3 are also explicitly and separately incorporated
26 herein in their entirety by reference. On page 1 of Ref. 3
27 it states: "For example, often only one bit is needed to
28 make a hole in which the casing will be set." On page 12 of
29 Ref. 3 it states in relation to tungsten carbide insert
30 roller cone bits: "Bit runs as long as 300 hours have been
31 achieved; in some instances, only one or two bits have been
32 needed to drill a well to total depth." This is particularly
33 so since the advent of the sealed bearing tri-cone bit
34 designs appeared in 1959 (Ref. 3, page 7) having tungsten

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1 carbide inserts (Ref. 3, page 12). Therefore, it is now
2 practical to talk about drill bits lasting long enough for
3 drilling a well during one pass into the formation, or
4 "one pass drilling".

5
6 b. Until recently, it has been impossible or
7 impractical to obtain sufficient geophysical information to
8 determine the presence or absence of oil and gas from inside
9 steel pipes in wells. Heretofore, either standard open-hole
10 logging tools or Measurement-While-Drilling ("MWD") tools
11 were used in the open hole to obtain such information.
12 Therefore, the industry has historically used various
13 open-hole tools to measure formation characteristics.
14 However, it has recently become possible to measure the
15 various geophysical quantities listed in Step 6 above from
16 inside steel pipes such as drill strings and casing strings.
17 For example, please refer to the book entitled "Cased Hole
18 Log Interpretation Principles/Applications", Schlumberger
19 Educational Services, Houston, Texas, 1989, an entire copy of
20 which is incorporated herein by reference. Please also refer
21 to the article entitled "Electrical Logging: State-of-the-
22 Art", by Robert E. Maute, The Log Analyst, May-June 1992,
23 pages 206-227, an entire copy of which is incorporated
24 herein by reference.

25
26 Because drill bits typically wore out during drilling
27 operations until recently, different types of metal pipes
28 have historically evolved which are attached to drilling
29 bits, which, when assembled, are called "drill strings".
30 Those drill strings are different than typical "casing
31 strings" run into the well. Because it was historically
32 absolutely necessary to do open-hole logging to determine the
33 presence or absence of oil and gas, the fact that different
34 types of pipes were used in "drill strings" and "casing

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1. strings" was of little consequence to the economics of
2 completing wells. However, it is possible to choose the
3 "drill string" to be acceptable for a second use, namely as
4 the "casing string" that is to be installed after drilling
5 has been completed.

6 7 8 New Drilling Process

9
10 Therefore, the preferred embodiments of the invention
11 herein reduces and simplifies the above 14 steps as follows:

12
13 Repeat Steps 1 - 2 above.

14
15 Steps 3 - 5 (Revised). Choose the drill bit so that
16 the entire production well can be drilled to its final depth
17 using only one single drill bit. Choose the dimensions of
18 the drill bit for desired size of the production well. If
19 the cement is to be cured under ambient hydrostatic
20 conditions, attach the drill bit to the bottom female threads
21 of the Latching Subassembly ("Latching Sub"). Choose the
22 material of the drill string from pipe material that can also
23 be used as the casing string. Here, any pipe made of any
24 material may be used including metallic pipe, composite pipe,
25 fiberglass pipe, and hybrid pipe made of a mixture of
26 different materials, etc. As an example, a composite pipe
27 may be manufactured from carbon fiber-epoxy resin materials.
28 Attach the first section of drill pipe to the top female
29 threads of the Latching Sub. Then rotary drill the
30 production well to its final depth during "one pass drilling"
31 into the well. While drilling, simultaneously circulate
32 drilling mud to carry the rock chips to the surface, to
33 prevent blowouts, to prevent excessive mud loss into
34 formation, to cool the bit, and to clean the bit.

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1 Step 6 (Revised). After the final depth of the
2 production well is reached, perform logging of the geological
3 formations to determine the amount of oil and gas present
4 from inside the drill pipe of the drill string. This
5 typically involves measurements from inside the drill string
6 of the necessary geophysical quantities as summarized in Item
7 "b." of "Several Recent Changes in the Industry". If such
8 logs obtained from inside the drill string show that no oil
9 or gas is present, then the drill string can be pulled out of
10 the well and the well filled in with cement. If commercial
11 amounts of oil and gas are present, continue the following
12 steps.

13
14 Steps 7 - 11 (Revised). If the cement is to be cured
15 under ambient hydrostatic conditions, pump down a Latching
16 Float Collar Valve Assembly with mud until it latches into
17 place in the notches provided in the Latching Sub located
18 above the drill bit.

19
20 Steps 12 - 13 (Revised). To "cure the cement under
21 ambient hydrostatic conditions", typically execute a two-plug
22 cementing procedure involving a first Bottom Wiper Plug
23 before and a second Top Wiper Plug behind the cement that
24 also minimizes cement contamination comprised of the
25 following individual steps:

26
27 A. Introduce the Bottom Wiper Plug into the
28 interior of the drill string assembled in the well and pump
29 down with cement that cleans the mud off the walls and
30 separates the mud and cement.

31
32 B. Introduce the Top Wiper Plug into the interior
33 of the drill string assembled into the well and pump down
34 with water thereby forcing the cement through any Float

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1 Collar Valve Assembly present and through the watercourses in
2 "a regular bit" or through the mud nozzles of a "jet bit" or
3 through any other mud passages in the drill bit into the
4 annulus between the drill string and the formation.
5

6 C. After the Bottom Wiper Plug, and Top Wiper
7 Plug have seated in the Latching Float Collar Valve Assembly,
8 release the pressure on the interior of the drill string that
9 results in the closing of the float collar which in turn
10 prevents cement from backing up in the drill string. The
11 resulting pressure release upon closure of the float collar
12 prevents distortions of the drill string that might prevent a
13 good cement seal as described earlier. I.e., "the cement is
14 cured under ambient hydrostatic conditions".
15

16 Repeat Step 14 above.
17

18 Therefore, the "New Drilling Process" has only
19 7 distinct steps instead of the 14 steps in the "Typical
20 Drilling Process". The "New Drilling Process" consequently
21 has fewer steps, is easier to implement, and will be less
22 expensive. The "New Drilling Process" takes less time to
23 drill a well. This faster process has considerable
24 commercial significance.
25

26 The preferred embodiment of the invention disclosed in
27 Figure 1 requires a Latching Subassembly and a Latching Float
28 Collar Valve Assembly. An advantage of this approach is that
29 the Float 32 of the Latching Float Collar Valve Assembly and
30 the Float Seating Surface 34 in Figure 1 are installed at the
31 end of the drilling process and are not subject to any wear
32 by mud passing down during normal drilling operations.
33
34

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1 The drill bit described in Figure 1 is a milled steel
2 toothed roller cone bit. However, any rotary bit can be used
3 with the invention. A tungsten carbide insert roller cone
4 bit can be used. Any type of diamond bit or drag bit can be
5 used. The invention may be used with any drill bit described
6 in Ref. 3 above that possesses mud passages, waterpassages,
7 or passages for gas. Any type of rotary drill bit can be
8 used possessing such passageways. Similarly, any type of bit
9 whatsoever that utilizes any fluid or gas that passes through
10 passageways in the bit can be used whether or not the bit
11 rotates.

12
13 In accordance with the above description, a preferred
14 embodiment of the invention is a method of making a cased
15 wellbore comprising at least the steps of: (a) assembling a
16 lower segment of a drill string comprising in sequence from
17 top to bottom a first hollow segment of drill pipe, a
18 latching subassembly means and a rotary drill bit having at
19 least one mud passage for passing drilling mud from the
20 interior of the drill string to the outside of the drill
21 string; (b) rotary drilling the well into the earth to a
22 predetermined depth with the drill string by attaching
23 successive lengths of hollow drill pipes to the lower segment
24 of the drill string and by circulating mud from the interior
25 of the drill string to the outside of the drill string during
26 rotary drilling so as to produce a wellbore; (c) after the
27 predetermined depth is reached, pumping a latching float
28 collar valve means down the interior of the drill string with
29 drilling mud until it seats into place within the latching
30 subassembly means; (d) pumping a bottom wiper plug means down
31 the interior of the drill string with cement until the bottom
32 wiper plug means seats on the upper portion of the latching
33 float collar valve means so as to clean the mud from the
34 interior of the drill string; (e) pumping any required

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1 additional amount of cement into the wellbore by forcing it
2 through a portion of the bottom wiper plug means and through
3 at least one mud passage of the drill bit into the wellbore;
4 (f) pumping a top wiper plug means down the interior of the
5 drill string with water until the top wiper plug seats on the
6 upper portion of the bottom wiper plug means thereby cleaning
7 the interior of the drill string and forcing additional
8 cement into the wellbore through at least one mud passage of
9 the drill bit; and (g) allowing the cement to cure, thereby
10 cementing into place the drill string to make a cased
11 wellbore.
12

13 In accordance with the above description, another
14 preferred embodiment of the invention is the rotary drilling
15 apparatus to drill a borehole into the earth comprising a
16 hollow drill string attached to a rotary drill bit having
17 at least one mud passage for passing the drilling mud from
18 within the hollow drill string to the borehole, a source of
19 drilling mud, a source of cement, and at least one latching
20 float collar valve means that is pumped with the drilling mud
21 into place above the rotary drill bit to install the latching
22 float collar means within the hollow drill string above the
23 rotary drill bit that is used to cement the drill string and
24 rotary drill bit into the earth during one pass into the
25 formation of the drill string to make a steel cased well.
26

27 In accordance with the above description, yet another
28 preferred embodiment of the invention is a method of drilling
29 a well from the surface of the earth and cementing a drill
30 string into place within a wellbore to make a cased well
31 during one pass into formation using an apparatus comprising
32 at least a hollow drill string attached to a rotary drill
33 bit, the bit having at least one mud passage to convey
34 drilling mud from the interior of the drill string to the

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1 wellbore, a source of drilling mud, a source of cement, and
2 at least one latching float collar valve assembly means,
3 using at least the following steps: (a) pumping the latching
4 float collar valve means from the surface of the earth
5 through the hollow drill string with drilling mud so as to
6 seat the latching float collar valve means above the drill
7 bit; and (b) pumping cement through the seated latching float
8 collar valve means to cement the drill string and rotary
9 drill bit into place within the wellbore.

10
11 **Figure 1A** shows another preferred embodiment of the
12 invention. Figure 1A shows a sectional view of the
13 embodiment shown in Figure 1 with the following exceptions.
14 In Figure 1A, the first stabilizer rib 75, and the second
15 stabilizer rib 77 are shown welded to the exterior of the
16 Latching Subassembly 18 of Figure 1. The third stabilizer
17 rib 79 (which is shown in Figures 1B and 1C that are
18 described below) is not shown in this section view. Also
19 shown is a diameter of the wellbore at a specific depth
20 designated by the distance between arrows A and B shown in
21 Figure 1A. The specific depth is defined by the variable Z
22 which is not shown in Figure 1A for the purposes of
23 simplicity. Sets of one or more stabilizer ribs comprise one
24 preferred type of stabilizer. Unit III, Lesson 1, of the
25 Rotary Drilling Series, previously incorporated by reference
26 above in Serial No. 08/323,152, now U.S. Patent No. 5,551,521
27 (which is the original parent application of this invention,
28 hereinafter "the '521 patent"), on page 36, states the
29 following with regards to stabilizers: "... blade-type
30 stabilizer ribs may be welded onto the lower end of the
31 housing...". Figure 48 in that Unit III, Lesson 1, on page
32 35, shows such stabilizers welded onto a "bottomhole
33 assembly". Such a bottomhole assembly is also called a
34 drilling apparatus. Unit II, Lesson 3, of the Rotary

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1 Drilling Series, previously incorporated by reference in the
2 '521 patent, shows various types of stabilizer arrangements
3 in Figure 18 on page 15, and in Figure 22 on page 21 that is
4 described on pages 20-22. These are all examples of drilling
5 stabilizer means. In particular, the type of stabilizer
6 shown in Figure 1A derives from the sketch shown as "A" in
7 Figure 22 within that Unit II, Lesson 3. There are many
8 other references to a stabilizer, or stabilizers, in the
9 Rotary Drilling Series and in the series entitled "Lessons in
10 Well Servicing and Workover", previously incorporated in
11 their entirety by reference in the '521 patent. Each such
12 stabilizer, or stabilizers, is an example of a drilling
13 stabilizer means.

14
15 Stabilizers are used to stabilize the bottomhole
16 assembly (BHA) as described in Unit III, Lesson 1, of the
17 Rotary Drilling Series, previously incorporated by reference
18 in the '521 patent, in the section entitled "Bottomhole
19 Assemblies" on pages 33-35. Accordingly, stabilizers are
20 used as a method for stabilizing the drill string while
21 drilling the wellbore.

22
23 Stabilizers are also used to centralize the drilling
24 apparatus in the wellbore. The utility of centralizers
25 during cementing operations is summarized in Unit II, Lesson
26 4, of the Rotary Drilling Series, previously incorporated by
27 reference in the '521 patent, as particularly explained on
28 page 1, in Figure 26 on page 29, in Figure 33 on page 35
29 entitled "centralizers" and in the related text on pages
30 35-38. The utility of centralizers during cementing
31 operations is further summarized in Lesson 4 of the series
32 entitled "Lessons in Well Servicing and Workover", previously
33 incorporated by reference in the '521 patent, on page 15, in
34 Figure 17 on page 18 and in the related text on pages 18-23,

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1 and on page 27. Accordingly, such stabilizers that also act
2 as centralizers are used as a method for maintaining the
3 casing portion in a substantially centralized position in
4 relation to a diameter of the wellbore. Element 46 in Figure
5 1A is relatively thin-wall casing, or drill pipe as the case
6 may be. As already described above, various different
7 drilling stabilizer means may be used as centralizer means so
8 that at least a portion of the drill string is centralized in
9 the well while cementing the drill string into place within
10 the wellbore by the presence of the drilling stabilizer
11 means. Accordingly, for the purposes herein, the stabilizer
12 ribs 75, 77, and 79 may also be called centralizer ribs 75,
13 77, and 79. Such a set of centralizer ribs is one preferred
14 embodiment of a centralizer means. So, an equivalent name
15 for stabilizer rib 75 is centralizer rib 75. An equivalent
16 name for stabilizer rib 77 is centralizer rib 77. An
17 equivalent name for stabilizer rib 79 is centralizer rib 79.
18 The relative scale for the stabilizer ribs 75 and 77 in
19 Figure 1 has been chosen to avoid confusion and for the
20 purpose of simplicity.

21
22 Figure 1B is an external view of the assembly shown in
23 Figure 1A, except here the milled tooth rotary drill bit 6
24 in Figure 1A is replaced with a jet bit 7 that has been
25 previously described above, that has jet nozzle 9.
26 Stabilizer rib 79 is shown in Figure 1B along with stabilizer
27 ribs 75 and 77 that were previously described. The scale of
28 these stabilizer ribs in Figure 1B does not correspond to the
29 scale in Figure 1A (that was chosen to prevent confusion and
30 for the purpose of simplicity in Figure 1A). These
31 stabilizer ribs are attached to the Latching Subassembly 18
32 in Figure 1B. The Latching Subassembly 18 is attached to
33 element 46 by a typical threaded pipe joint 19. Element 46
34 in Figure 1 is quoted from above as a "relatively thin-walled

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1 casing, or drill pipe" as the case may be. The three
2 stabilizer ribs shown in Figure 1B are an example of multiple
3 stabilizer ribs attached to the exterior of a latching
4 subassembly means to stabilize the drill string during
5 drilling. Unit I, Lesson 2, of the Rotary Drilling Series,
6 previously incorporated by reference in the '521 patent,
7 shows diagrams of jet nozzles in Figure 5 on page 4, in
8 Figure 22 on page 18, and there is a section entitled "Jet
9 nozzle factors" on page 13 that describes jet nozzles. It
10 should be appreciated that the multiple stabilizer ribs may
11 be attached to any portion of the drilling apparatus.
12 Accordingly, the multiple stabilizer ribs may be attached to
13 some, or all, of the individual lengths of casings that make
14 up the drill string. As stated before, stabilizer ribs 75,
15 77, and 79 may also act as centralizer ribs, constituting one
16 preferred embodiment of a centralizer means.

17
18 **Figure 1C** is the same as Figure 1B except the jet bit 7
19 has been replaced with jet deflection roller cone bit 11
20 having an eccentric jet nozzle 13 that is used for
21 directional drilling. In addition, the Latching Subassembly
22 18 in Figure 1B is replaced with any suitable bottomhole
23 assembly (BHA) 21. The upper portion of the bottomhole
24 assembly 21 is attached to element 46 by a suitable threaded
25 joint 23. The external elements of Figure 1C are very
26 similar to those shown in the Unit III, Lesson 1, of the
27 Rotary Drilling Series, previously incorporated by reference
28 in the '521 patent, in Figure 32 on page 25 and also shown in
29 Figure 1E of the current application. Figure 31 on page 25
30 of that Unit III, Lesson 1, shows a "jet deflection roller
31 cone bit", which is used for directional drilling purposes as
32 explained in the section entitled "Jet deflection bits" on
33 pages 25-26 of that Unit III, Lesson 1. Unit I, Lesson 2, of
34 the Rotary Drilling Series, previously incorporated by

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1 reference in the '521 patent, shows diagrams of a jet bit
2 having an eccentric orifice used for directional drilling in
3 Figure 22 on page 18, and in Figure 51 on page 39. For
4 example, in relation to that Figure 22 on page 18 of that
5 Unit I, Lesson 2, it states: "...and the large jet is pointed
6 so that, when pump pressure is applied, the jet washes out
7 the side of the hole in a specific direction." As another
8 example, in relation to that Figure 51 on page 39 of that
9 Unit I, Lesson 1, it further states: "Special-purpose jet
10 bits have also been designed for use in directional
11 drilling." This page 39 of that Unit I, Lesson 1, further
12 states: "The large amount of mud emitted from the enlarged
13 jet washes away the formation in front of the bit, and the
14 bit follows the path of least resistance." Accordingly, this
15 type of bit provides a means to perform directional drilling.
16 Accordingly, this apparatus provides a directional drilling
17 means. Put another way, this is a rotary drilling apparatus
18 to drill a borehole into the earth comprising a hollow drill
19 string possessing directional drilling means comprised of a
20 jet deflection bit having at least one mud passage for
21 passing drilling mud from within the hollow drill string to
22 the borehole. Figure 1C also shows centralizer ribs 75, 77,
23 and 79 that were previously described. These three
24 stabilizer ribs shown in Figure 1C are another example of
25 multiple stabilizer ribs attached to the exterior of a
26 latching subassembly means to stabilize the drill string
27 during drilling. It should be appreciated that the multiple
28 stabilizer ribs may be attached to any portion of the
29 drilling apparatus. Accordingly, the multiple stabilizer
30 ribs may be attached to some, or all, of the individual
31 lengths of casings that make up the drill string. As stated
32 before, stabilizer ribs 75, 77, and 79 are also used as
33 centralizer ribs 75, 77, and 79 constituting one preferred
34 embodiment of a centralizer means.

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1 Figure 1D shows stabilizer ribs 81, 83, and 85 attached
2 to a typical length of casing 87. Casing 87 is attached to
3 upper casing 89 by threaded joint 91. Casing 87 is attached
4 to lower casing 93 by threaded joint 95. Accordingly, the
5 multiple stabilizer ribs may be attached to some, or all, of
6 the individual lengths of casings that make up the drill
7 string. The stabilizer ribs act to stabilize the drill
8 string made of at least a portion of casing lengths as shown
9 in Figure 1D. A drill string having one or more casing
10 lengths with stabilizer ribs attached is yet another
11 embodiment of drilling stabilizer means. As previously
12 explained above in relation to Figure 1A, such stabilizers
13 that also act as centralizers are used as a method for
14 maintaining the casing portion in a substantially centralized
15 position in relation to a diameter of the wellbore.
16 As already described above, various different drilling
17 stabilizer means may be used as centralizer means so that at
18 least a portion of the drill string is centralized in the
19 well while cementing the drill string into place within the
20 wellbore by the presence of the drilling stabilizer means.
21 In one embodiment, an upper drill string made from drill pipe
22 is attached to a lower set of casings assembled in the well.
23 Stabilizer ribs 81, 83, and 85 may also be called
24 equivalently centralizer ribs 81, 83 and 85 for the purposes
25 herein and are one preferred embodiment of a centralization
26 means.

27
28 In the above, stabilizer ribs attached to drill strings
29 have been described which are examples of stabilization
30 means. In the above, stabilizer ribs have been described
31 that act as centralization means. Accordingly, one preferred
32 embodiment of the invention is the method of using
33 stabilization means attached to drill strings to act as
34

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1 centralization means when the drill strings are cemented into
2 place in a wellbore as the well casing.

3
4 The various drill bits drill through different earth
5 formations. Lesson 2 of the series entitled "Lessons in Well
6 Servicing and Workover", that was previously incorporated by
7 reference in the '521 patent, on pages 2-10, describes rocks
8 and minerals, sedimentary rocks, shale, metamorphic rocks,
9 igneous rocks, as examples of earth formations. Unit I,
10 Lesson 2, of the Rotary Drilling Series, previously
11 incorporated by reference in the '521 patent, on page 1,
12 describes "rock formations" and states: "formations consist
13 of alternating layers of soft material, hard rocks, and
14 abrasive sections". During the drilling process, the drill
15 bit removes the different portions of earth formations, and
16 then the mud transports the cuttings from the earth
17 formations to the surface. Different drill bits have been
18 described including the milled tooth rotary drill bit 6
19 having milled steel roller cones in Figure 1; the jet bit 7
20 in Figure 1B; and the jet deflection roller cone bit 11 in
21 Figure 1C. There are yet other types of drill bits described
22 in Unit I, Lesson 2, of the Rotary Drilling Series,
23 previously incorporated by reference in the '521 patent.
24 Any type of rotary drill bit whatsoever may be used to drill
25 the borehole through the earth. These different types of
26 drill bits all remove portions of earth formations.
27 Accordingly, each different drill bit attached to a drill
28 string is an earth removal member, a term that is defined
29 herein. The earth removal member may also be defined to be
30 an earth removal means and/or a drill bit means. The terms
31 "earth removal member", "earth removal member means", "earth
32 removal means", and "drill bit means" may be used
33 interchangeably for the purposes of this invention.

34
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1 Element 46 in Figure 1 is quoted from above as
2 "relatively thin-walled casing, or drill pipe" as the case
3 may be. Element 46 is also so identified in Figure 1A,
4 in Figure 1B, and in Figure 1C. In Figure 1, the Latching
5 Subassembly 18 is used to operatively connect the earth
6 removal member (6) to a drill pipe (46). In Figure 1,
7 elements 6, 18, and 46, and the related description provide a
8 method of drilling the wellbore using a drill string, the
9 drill string having an earth removal member operatively
10 connected thereto. The term "drill string" in relation to
11 Figure 1 includes elements 6, 18, and 46. In a preferred
12 embodiment, element 46 is that portion of the drill string
13 that is casing which is used to line the wellbore. In
14 accordance with the invention, element 46 is also used as a
15 casing portion for lining the wellbore. Previous description
16 in relation to Figure 1 describes methods of locating the
17 casing portion 46 within the wellbore.

18
19 In accordance with the above, a preferred embodiment of
20 the invention is a rotary drilling apparatus to drill a
21 borehole into the earth comprising a hollow drill string
22 possessing at least one drilling stabilizer means, the drill
23 string attached to a rotary drill bit having at least one mud
24 passage for passing the drilling mud from within the hollow
25 drill string to the borehole, a source of drilling mud, a
26 source of cement, and at least one latching float collar
27 valve means that is pumped with the drilling mud into place
28 above the rotary drill bit to install the latching float
29 collar means within the hollow drill string above the rotary
30 drill bit that is used to cement the drill string and rotary
31 drill bit into the earth during one pass into the formation
32 of the drill string to make a steel cased well.

33
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1 In accordance with the above, another preferred
2 embodiment of the invention is a method of drilling a well
3 from the surface of the earth and cementing a drill string
4 into place within a wellbore to make a cased well during one
5 pass into formation using an apparatus comprising at least a
6 hollow drill string possessing at least one drilling
7 stabilizer means, the drill string attached to a rotary drill
8 bit, the bit having at least one mud passage to convey
9 drilling mud from the interior of the drill string to the
10 wellbore, a source of drilling mud, a source of cement, and
11 at least one latching float collar valve assembly means,
12 using at least the following steps: (a) pumping the latching
13 float collar valve means from the surface of the earth
14 through the hollow drill string with drilling mud so as to
15 seat the latching float collar valve means above the drill
16 bit; and (b) pumping cement through the seated latching float
17 collar valve means to cement the drill string and rotary
18 drill bit into place within the wellbore, whereby at least a
19 portion of the drill string is centralized in the well while
20 cementing the drill string into place within the wellbore by
21 the presence of the drilling stabilizer means.

22
23 In accordance with the above, a preferred embodiment of
24 the invention provides a method for drilling and lining a
25 wellbore comprising: drilling the wellbore using a drill
26 string, the drill string having an earth removal member
27 operatively connected thereto and a casing portion for lining
28 the wellbore; stabilizing the drill string while drilling the
29 wellbore; locating the casing portion within the wellbore;
30 and maintaining the casing portion in a substantially
31 centralized position in relation to a diameter of the
32 wellbore.

33
34
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1 In accordance with the above, another preferred
2 embodiment of the invention is the method wherein following
3 the lining of the wellbore with the above defined casing
4 portion, the casing portion is cemented into place using at
5 least the following steps: (a) pumping a latching float
6 collar valve means from the surface of the earth through the
7 drill string with drilling mud so as to seat the latching
8 float collar valve means above the earth removal member,
9 wherein the earth removal member possesses at least one mud
10 passage to convey drilling mud from the interior of the drill
11 string to the wellbore; and (b) pumping cement through the
12 seated latching float collar valve means to cement the drill
13 string and the earth removal member into place within the
14 wellbore.

15
16 Figure 1E is a rendition of the left-hand portion of
17 Figure 32 on page 25 of Unit III, Lesson 1, of the Rotary
18 Drilling Series. An entire copy of Unit III, Lesson 1, of
19 the Rotary Drilling Series was previously incorporated by
20 reference into the '521 patent. The title of that Figure 32
21 is "Deflecting Hole with Jet Deflection Bit". Jet deflection
22 bit 15 is attached to "an angle-building bottomhole assembly"
23 17 having stabilizer rib 97. The phrase "an angle-building
24 bottomhole assembly" is defined on page 25 of Unit III,
25 Lesson 1, of the Rotary Drilling Series. That angle-building
26 bottomhole assembly 17 is in turn attached to drill pipe.
27 Drilling with stabilizers attached to drill pipe is
28 shown in Figure 1E.

29
30 Figure 1F is a rendition of Figure 5 on page 4 of
31 Unit I, Lesson 2, of the Rotary Drilling Series. An entire
32 copy of Unit I, Lesson 2, of the Rotary Drilling Series was
33 previously incorporated by reference in the '521 patent.
34 The title of that Figure 5 is "Fluid Passageways in a Jet

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1 Bit". Jet bit 31 is shown in Figure 1F. Three mud jets are
2 shown in Figure 1F, although they are not numbered.

3
4 The directional drilling of wells was described above
5 in relation to Figure 1C. Unit III, Lesson 1, of the Rotary
6 Drilling Series, previously incorporated by reference in the
7 '521 patent, describes "directional wells" on page 2;
8 "directional drilling" on page 2; and "steering tools"
9 on page 19. As stated above in relation to Figure 1C,
10 that Unit III, Lesson 1, describes how to use a jet
11 deflection bit, and for example, on page 25 thereof, it
12 states the following: "The tool face (the side of the bit
13 with the oversize nozzle) is oriented in the desired
14 direction, the pumps started, and the drill string worked
15 slowly up and down, without rotation, about 10 feet off the
16 bottom. This action washes out the formation on one side
17 (fig. 32). When rotation is started and weight applied, the
18 bit tends to follow the path of least resistance - the
19 washed-out section."

20
21 That Unit III, Lesson 1, on page 44 of the Glossary,
22 also defines the term "measurement while drilling" to be the
23 following: "1. directional surveying during routine drilling
24 operations to determine the angle and direction by which the
25 wellbore deviates from the vertical. 2. any system of
26 measuring downhole conditions during routine drilling
27 operations." That Unit III, Lesson 1, page 18, further
28 describes a "steering tool" to be a "wireline telemetry
29 surveying instrument that measures inclination and direction
30 while drilling is in progress (fig. 22)." A wireline
31 steering tool is shown in Figure 22 on page 19 of that
32 Unit III, Lesson 1. The steering tool is periodically
33 introduced into the wellbore while the rotary drilling is
34 temporarily stopped, the direction of the well is suitably

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1 measured, the tool face properly oriented as described in the
2 previous paragraph, the well suitably directionally drilled
3 as described in the previous paragraph, and then the steering
4 tool is removed from the well and rotary drilling commenced.
5 The steering tool is removed from the drill pipe before
6 completion operations begin. The steering tool is an example
7 of a steering tool means, that is also called a directional
8 surveying means, which measures the direction of the wellbore
9 being drilled. Accordingly, methods and apparatus have been
10 described that provide for periodically halting rotary
11 drilling, introducing into the wellbore a directional
12 surveying means to determine the direction of the wellbore
13 being drilled, and thereafter removing the directional
14 surveying means from the wellbore.

15
16 A steering tool may be used with jet deflection bits and
17 with downhole mud motors (the mud motors will be described in
18 detail later). Accordingly, the orientation of the jet
19 deflection bit determines the directional drilling of the
20 borehole, and the steering tool may be used to measure its
21 direction. The orientation of the jet deflection bit may be
22 changed at will depending upon the directional information
23 received from the steering tool. Therefore, methods and
24 apparatus have been described which may be used to determine
25 and change a drilling trajectory of a well. Accordingly,
26 methods and apparatus have been provided for rotary drilling
27 the well into the earth in a desired direction. Accordingly,
28 methods and apparatus have been described for selectively
29 causing a drilling trajectory to change during the drilling
30 of a well. Accordingly, apparatus has been provided that is
31 a directional drilling means. As described above, one type
32 of directional drilling means includes a jet deflection bit.
33 There are many other types of directional drilling means as
34 described in Unit III, Lesson 1, of the Rotary Drilling

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1 Series. Put another way, one preferred embodiment the
2 invention is a rotary drilling apparatus to drill a borehole
3 into the earth comprising a hollow drill string possessing
4 directional drilling means comprising a jet deflection bit
5 having at least one mud passage for passing the drilling mud
6 from within the hollow drill string to the borehole.

7
8 Accordingly, a preferred embodiment of the invention is
9 a method of directional drilling a well from the surface of
10 the earth and cementing a drill string into place within a
11 wellbore to make a cased well during one pass into formation
12 using an apparatus comprising at least a hollow drill string
13 attached to a rotary drill bit possessing directional
14 drilling means, the bit having at least one mud passage
15 to convey drilling mud from the interior of the drill
16 string to the wellbore, a source of drilling mud, a source
17 of cement, and at least one latching float collar valve
18 assembly means.

19
20 In relation to Figures 1, 1A, 1B, and 1C, element 46 has
21 been previously described as a casing portion for lining the
22 wellbore. Accordingly, methods and apparatus have been
23 described for lining the wellbore with the casing portion.
24 The term "earth removal member" has been previously defined
25 above. Therefore, a preferred embodiment of the invention is
26 a method for drilling and lining a wellbore comprising:
27 drilling the wellbore using a drill string, the drill string
28 having an earth removal member operatively connected thereto
29 and a casing portion for lining the wellbore; selectively
30 causing a drilling trajectory to change during the drilling;
31 and lining the wellbore with the casing portion.

32
33 In an embodiment of the present invention, the phrase
34 "selectively causing a drilling trajectory to change during

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1 drilling" may include the following. The term "during
2 drilling" may mean, in one embodiment of the present
3 invention, that any measurements required are performed
4 without having to remove the casing from the well, so that
5 any "directional drilling measurement means" used in this
6 drilling process would not require the removal of the casing
7 from the well. "Selectively" may mean, in one embodiment,
8 that the direction may be determined at any time during the
9 drilling, and the direction of the drilling changed at any
10 time during drilling, at will, without removing the casing
11 from the well, or without drilling any advanced holes into
12 the earth. The term "selectively" may also be defined to
13 mean, in one embodiment of the present invention, that the
14 direction of drilling may be measured any number of times
15 with a directional drilling measurement means, and the
16 direction of the drilling may be changed any number of times
17 with a directional drilling means, without removing the
18 casing from the well, or without drilling any advanced holes
19 into the earth.

20
21 Another preferred embodiment of the invention is the
22 above method, wherein following the lining of the wellbore
23 with the casing portion, the casing portion is cemented into
24 place using at least the following steps: (a) pumping a
25 latching float collar valve means from the surface of the
26 earth through the drill string with drilling mud so as to
27 seat the latching float collar valve means above the earth
28 removal member, whereby the earth removal member possesses
29 at least one mud passage to convey drilling mud from the
30 interior of the drill string to the wellbore; and (b) pumping
31 cement through the seated latching float collar valve means
32 to cement the drill string and earth removal member into
33 place within the wellbore.

34
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1 Step 6 (Revised), as quoted above, and from the '521
2 patent, states the following: "After the final depth of the
3 production well is reached, perform logging of the geological
4 formations to determine the amount of oil and gas present
5 from inside the drill pipe of the drill string. This
6 typically involves measurements from inside the drill
7 string of the necessary geophysical quantities summarized in
8 Item "b" of "Several Recent Changes in the Industry." The
9 term 'Measurement-While-Drilling ("MWD")' is a term that is
10 also defined in the '521 patent.

11
12 Lesson 3 of the series entitled "Lessons in Well
13 Servicing and Workover", previously incorporated by
14 reference in the '521 patent, on page v, lists entire
15 chapters on the following subjects: "Electric Logging",
16 "Acoustic Logging", "Nuclear Logging", "Temperature Logging",
17 "Production Logging", and "Computer-generated Logging".

18
19 That Lesson 3 of the series entitled "Lessons in Well
20 Servicing and Workover", on pages 4-5, states the following:
21 "In general, three types of wireline log are available:
22 electrical, acoustic, and nuclear. Electric logs measure
23 natural and induced electrical properties of formations;
24 acoustic, or sonic, logs measure the time it takes for sound
25 to travel through a formation; and nuclear logs measure
26 natural and induced radiation in formations. These
27 measurements are interpreted to reveal the presence of oil,
28 gas and water, the porosity of a formation, and many other
29 characteristics pertinent to completing or recompleting
30 a well successfully." Lesson 3 further states the following
31 on pages 4-5: "In addition to electric, acoustic, and
32 nuclear logs, other wireline logging devices are widely
33 utilized. For example, caliper logs, which measure wellbore
34 diameter, use flexible mechanical arms with pads that contact

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1 the wall of the hole. Directional and dipmeter surveys,
2 determine hole angle, direction, and formation dip, using
3 mechanical and electrical measurements." Lesson 3 further
4 states the following on pages 4-5: "Wireline logging tools
5 are designed for running either in open hole or in cased
6 hole." Lesson 3 further states the following on pages 4-5:
7 "Cased-hole logging is accomplished after the casing is set
8 in the hole."
9

10 Lesson 3 of the series entitled "Lessons in Well
11 Servicing and Workover" on page 44, in the Glossary, defines
12 "logging devices" as follows: "any of several electrical,
13 acoustical, mechanical, or nuclear devices that are used to
14 measure and record certain characteristics or events that
15 occur in a well that has been or is being drilled". For
16 the purposes herein, the term "logging means" is defined to
17 include any "logging device". The term "measurement while
18 drilling (MWD)" was previously defined above. Lesson 3 of
19 the series entitled "Lessons in Well Servicing and Workover",
20 on page 44, defines the term "Logging while drilling (LWD)"
21 to be the following: "logging measurements obtained by
22 measurement-while-drilling techniques as the well is being
23 drilled."
24

25 As explained above, logging devices may be lowered into
26 a drill string, geophysical data obtained from within the
27 drill string, and then the logging devices removed, and
28 rotary drilling begun again. In this way, geophysical data
29 may be obtained from within a drill string. In one preferred
30 embodiment, geophysical data may be obtained from within a
31 nonrotating drill string. The geophysical data, or
32 geophysical quantities, otherwise also called geophysical
33 parameters, may be measured with sensors that are within the
34 appropriate logging device. Accordingly, a logging device

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1 possesses a geophysical parameter sensing member. Such a
2 geophysical parameter sensing member may also be defined
3 herein as a geophysical parameter sensing means or simply, as
4 a geophysical sensing means. Geophysical parameter sensing
5 members are used within the drill string shown in Figure 1 to
6 obtain the appropriate geophysical quantities. In one
7 preferred embodiment of the invention, the drill string is
8 not rotating while the geophysical parameter sensing members
9 are used to obtain the appropriate geophysical quantities.
10 In one embodiment, the geophysical parameter sensing member
11 obtains its information from within the drill string. Put
12 another way, the geophysical parameter sensing member obtains
13 its information from within steel pipe, be it drill pipe, or
14 casing. In one preferred embodiment herein, the geophysical
15 parameter sensing member does not obtain its information in
16 the open borehole. An important element of a preferred
17 embodiment of the invention is the method of obtaining all
18 geophysical data from within a steel pipe that is necessary
19 to determine the amount of oil and gas located adjacent to
20 the steel pipe located in a geological formation.

21
22 In relation to Figures 1, 1A, 1B, and 1C, element 46
23 shows a drill string having a casing portion for lining the
24 wellbore. In relation to Figures 1, 1A, 1B, and 1C, the term
25 "earth removal member" has been defined. For example, as
26 previously defined above, in relation to Figure 1, an example
27 of an earth removal member is element 6 which is attached to
28 the Latching Subassembly 18, which is in turn attached to the
29 relatively thin-wall casing, or drill pipe, designated as
30 element 46 in that Figure 1. In one embodiment, the Latching
31 Subassembly 18 is defined for the purposes herein to be a
32 drilling assembly. Hence, this Figure 1, and Figures 1A, 1B,
33 and 1C, show a drilling assembly operatively connected to the
34 drill string and having an earth removal member. When the

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1 logging device, which possess a geophysical parameter sensing
2 member, is inserted into element 46, then that assembled
3 apparatus is an example of a drilling assembly operatively
4 connected to the drill string and having an earth removal
5 member and a geophysical parameter sensing member. Figure 1
6 shows an apparatus for drilling a wellbore. Accordingly, a
7 preferred embodiment of the invention is an apparatus for
8 drilling a wellbore comprising: a drill string having a
9 casing portion for lining the wellbore; a drilling assembly
10 operatively connected to the drill string and having an earth
11 removal member and a geophysical parameter sensing member.
12

13 Accordingly, another preferred embodiment of the
14 invention is the previously described apparatus further
15 comprising a latching float collar valve means which, after
16 the removal of the geophysical parameter sensing member from
17 the wellbore, is pumped from the surface of the earth through
18 the drill string with drilling mud so as to seat the latching
19 float collar valve means above the earth removal member.
20

21 In accordance with the above, yet another preferred
22 embodiment of the invention includes ceasing rotary drilling
23 with the drill string on at least one occasion, introducing
24 into the drill string a logging device having at least one
25 geophysical parameter sensing member, measuring at least one
26 geophysical parameter with the geophysical parameter sensing
27 member, and removing the logging device from the drill
28 string.
29

30 In accordance with the above, yet another preferred
31 embodiment of the invention is a rotary drilling apparatus to
32 drill a borehole into the earth comprising a hollow drill
33 string, possessing at least one geophysical parameter sensing
34 member, attached to a rotary drill bit having at least one

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1 mud passage for passing the drilling mud from within the
2 hollow drill string to the borehole, a source of drilling
3 mud, a source of cement, and at least one latching float
4 collar valve means that is pumped with the drilling mud into
5 place above the rotary drill bit to install the latching
6 float collar means within the hollow drill string above the
7 rotary drill bit that is used to cement the drill string and
8 rotary drill bit into the earth during one pass into the
9 formation of the drill string to make a steel cased well.

10
11 In accordance with the above, yet another preferred
12 embodiment of the invention is a method of drilling a well
13 from the surface of the earth and cementing a drill string
14 into place within a wellbore to make a cased well during one
15 pass into formation using an apparatus comprising at least a
16 hollow drill string, possessing at least one geophysical
17 parameter sensing member, attached to a rotary drill bit, the
18 bit having at least one mud passage to convey drilling mud
19 from the interior of the drill string to the wellbore, a
20 source of drilling mud, a source of cement, and at least one
21 latching float collar valve assembly means, using at least
22 the following steps: (a) pumping the latching float collar
23 valve means from the surface of the earth through the hollow
24 drill string with drilling mud so as to seat the latching
25 float collar valve means above the drill bit; and (b) pumping
26 cement through the seated latching float collar valve means
27 to cement the drill string and rotary drill bit into place
28 within the wellbore, whereby the geophysical parameter
29 sensing member is used to measure at least one geophysical
30 parameter from within the drill string.

31
32 A preferred embodiment of the invention is to allow the
33 cement in the annulus between the drill pipe and the hole to
34 cure under ambient hydrostatic conditions. In this preferred

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1 embodiment, the cement sets up under these ambient
2 hydrostatic conditions. As described above, this allows the
3 cement to properly cure.

4
5 Unit II, Lesson 4, of the Rotary Drilling Series, an
6 entire copy of which was incorporated into the '521 patent,
7 on page 38, defines a "cement slurry". That Unit II,
8 Lesson 4, on pages 41-42 further defines "Oilwell Cements and
9 Additives", "API Classes of Cement", "Class A", "Class B",
10 "Class C", "Class D", "Class E", "Class F", "Class G",
11 "Class H", and "Class J". That Unit II, Lesson 4, on
12 pages 43-44, further describes "Additives", "Retarders",
13 "Accelerants", "Dispersants", and "Heavyweight Additives".
14 That Unit II, Lesson 4, on pages 46-47, further describes
15 "Lightweight additives", "Extenders", "Bridging materials",
16 "Other additives", a "slurry", "Thixotropic cement",
17 "Pozzolan cement", and "Expanding Cement". These different
18 materials are all examples of "physically alterable bonding
19 materials". These are also examples of "physically alterable
20 bonding means". They bond between the casing and the
21 annulus. So, they are a bonding materials. These materials
22 also physically change their state from a liquid to a solid.
23 Consequently, these diverse materials may be properly defined
24 as a group to be "physically alterable bonding materials".
25 These physically alterable bonding materials are placed in
26 the annulus between the casing and the wellbore and allowed
27 to cure.

28
29 There are other examples of embodiments of "physically
30 alterable bonding materials". For example, U.S. Patent
31 No. 3,960,801 that issued on June 1, 1976, that is entitled
32 "Pumpable Epoxy Resin Composition", an entire copy of which
33 is incorporated herein by reference, describes using epoxy
34 resin compounds that cure to "a hard impermeable solid" in

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1 subterranean formations. As another example, U.S. Patent
2 No. 4,489,785 that issued on December 25, 1984, that is
3 entitled "Method of Completing a Well Bore Penetrating
4 Subterranean Formation", an entire copy of which is
5 incorporated herein by reference, also describes using epoxy
6 resins to form a "substantially crack-free, impermeable
7 solid" in subterranean formations. As yet another example,
8 U.S. Patent No. 5,159,980 that issued on November 3, 1992,
9 that is entitled "Well Completion and Remedial Methods
10 Utilizing Rubber Latex Compositions", an entire copy of which
11 is incorporated herein by reference, describes making a
12 "solid rubber plug or seal" in a subterranean geological
13 formation. These materials also physically change their
14 state from a liquid to a solid. Consequently, these
15 materials may be defined as "physically alterable bonding
16 materials". These physically alterable bonding materials are
17 placed in the annulus between the casing and the wellbore and
18 allowed to cure. These "physically alterable bonding
19 materials" are examples of "physically alterable bonding
20 means" or "physically alterable bonding material means" which
21 are terms defined herein. For the purposes of this
22 invention, the terms "physically alterable bonding
23 materials", "physically alterable bonding means", and
24 "physically alterable bonding material means" may be used
25 interchangeably.

26
27 Unit I, Lesson 3, of the Rotary Drilling Series, an
28 entire copy of which was incorporated within the '521 patent,
29 on page 40, in the Glossary, defines "tubular goods" to be
30 the following: "any kind of pipe, also called a tubular.
31 Oil field tubular goods including tubing, casing, drill pipe,
32 and line pipe." Previous description related to Figure 1
33 has described a method for lining a wellbore with a casing
34 portion, that is element 46, in Figure 1. Therefore, in

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1 accordance with the definition of a tubular, a method for
2 lining a wellbore with a tubular has been described in
3 relation to Figure 1.

4
5 As previously described above, in Figure 1, elements 6,
6 18 and 46 may comprise a drill string. The casing portion of
7 that drill string is shown as element 46 in Figure 1.
8 Therefore, description in relation to Figure 1 has described
9 drilling the wellbore using a drill string, the drill string
10 having a casing portion. Previous disclosure above in
11 relation to Figure 1 has described locating the casing
12 portion within the wellbore. Previous disclosure in relation
13 to Figure 1 has described placing cement in an annulus formed
14 between the casing portion (46) and the wellbore (2). The
15 term "physically alterable bonding material" has been defined
16 above. Therefore, Figure 1 and the related disclosure has
17 provided a method of placing a physically alterable bonding
18 material in an annulus formed between the casing portion and
19 the wellbore.

20
21 A portion of the above specification states the
22 following: 'As the water pressure is reduced on the inside
23 of the drill pipe, then the cement in the annulus between the
24 drill pipe and the hole can cure under ambient hydrostatic
25 conditions. This procedure herein provides an example of the
26 proper operation of a "one-way cement valve means".'
27 Therefore, methods have been described in relation to
28 Figure 1 for establishing a hydrostatic pressure condition in
29 the wellbore and allowing the cement to cure under the
30 hydrostatic pressure condition. In relation to the
31 definition of a physically alterable bonding material,
32 therefore, methods have been described in relation to
33 Figure 1 for establishing a hydrostatic pressure condition

34
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1 in the wellbore, and allowing the bonding material to
2 physically alter under the hydrostatic pressure condition.

3
4 Accordingly, a preferred embodiment of the invention is
5 a method for lining a wellbore with a tubular comprising:
6 drilling the wellbore using a drill string, the drill string
7 having a casing portion; locating the casing portion within
8 the wellbore; placing a physically alterable bonding material
9 in an annulus formed between the casing portion and the
10 wellbore; establishing a hydrostatic pressure condition in
11 the wellbore; and allowing the bonding material to physically
12 alter under the hydrostatic pressure condition.

13
14 Put another way, the above embodiment has described a
15 method for lining a wellbore with a tubular having at least
16 the following steps: drilling the wellbore using a drill
17 string attached to an earth removal member, the drill string
18 having a casing portion; locating the casing portion within
19 the wellbore; placing a physically alterable bonding material
20 in an annulus formed between the casing portion and the
21 wellbore; establishing a hydrostatic pressure condition in
22 the wellbore; and allowing the bonding material to physically
23 alter under the hydrostatic pressure condition.

24
25 In accordance with the above, methods have been
26 described to allow physically alterable bonding material to
27 cure thereby encapsulating the drill string in the wellbore
28 with cured bonding material. In accordance with the above,
29 methods have been described for encapsulating the drill
30 string and rotary drill bit within the borehole with cured
31 bonding material during one pass into formation. In
32 accordance with the above, methods have been described for
33 pumping physically alterable bonding material through a float
34 collar valve means to encapsulate a drill string and rotary

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1 drill bit with cured bonding material within the wellbore.
2 In accordance with the above, methods have been described for
3 encapsulating the drill string and rotary drill bit within
4 the borehole with a physically alterable bonding material and
5 allowing the bonding material to cure.

6
7 Unit III, Lesson 2, of the Rotary Drilling Series,
8 previously incorporated by reference into the '521 patent,
9 on page 1, describes a "retrieved cable-tool bit". Lesson 8
10 of the series entitled "Lessons in Well Servicing and
11 Workover", previously incorporated by reference in the '521
12 patent, on page 23 describes an "underreamer" that may be
13 used as a retrievable bit during drilling. In one embodiment
14 of the present invention, the underreamer may be used as a
15 retrievable bit during casing drilling. Page 23 of Unit III,
16 Lesson 2, of the Rotary Drilling Series further states in
17 relation to an underreamer: "...similar to an underreamer
18 in that the cutters can be expanded by hydraulic pressure".
19 Lesson 8 in this series further describes on page 15 a
20 "retrievable packer" and in relation to Figure 21 on that
21 page 15, also describes a "Retrievable Squeeze Tool".
22

23 There are other examples of retrievable elements used
24 in the oil and gas industry. Lesson 4 of the series entitled
25 "Lessons in Well Servicing and Workover", previously
26 incorporated by reference in the '521 patent, on page 30,
27 describes a "retrievable collar". Lesson 1 of the series
28 entitled "Lessons in Well Servicing and Workover", previously
29 incorporated by reference in the '521 patent, on page 22
30 describes "how a crew retrieves a sucker rod pump"; on
31 page 24 describes "Rod String Retrieval" and "Tubing
32 Retrieval"; and on page 27, describes a "Retrievable
33 production packer".
34

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1 In Figure 1, milled tooth rotary drill bit 6 is attached
2 to Latching Subassembly 18 and Latching Float Collar Valve
3 Assembly 20 is located within the Latching Subassembly.
4 The Latching Float Collar Valve Assembly may be selectively
5 retrieved following cementing operations. So, a selectively
6 removable assembly (for example, the Latching Float Collar
7 Valve Assembly 18) is connected to the drill bit 6 by a
8 mechanical means (for example, the Latching Float Collar
9 Valve Assembly 20). In one preferred embodiment of the
10 invention, these elements comprise a drilling assembly.
11 Accordingly, in relation to Figure 1, the above has described
12 one embodiment of a portion of the drilling assembly being
13 selectively removable from the wellbore without removing the
14 casing portion.

15
16 In another preferred embodiment of the invention, the
17 Upper Seal 22 of the Latching Float Collar Valve Assembly can
18 be replaced with a solid, retrievable plug. That solid
19 retrievable plug is designated with element 5, but is not
20 shown in Figure 1 in the interest of brevity. After the
21 Latching Float Collar Valve Assembly is pumped downhole with
22 the solid retrievable plug in place, the solid retrievable
23 plug may be suitably retrieved from the well before cementing
24 operations are commenced. As yet another preferred
25 embodiment of the invention, a retrievable wiper plug can be
26 placed in the wellbore above Upper Seal 22 that is used to
27 force down the Latching Float Collar Valve Assembly using
28 hydraulic pressure applied in the wellbore. An example of
29 such a wiper plug is the wiper plug that is generally shown
30 as element 604 in Figure 15. Upper wiper attachment
31 apparatus 606 may be used to retrieve the wiper plug. Wiper
32 attachment apparatus 606 may be retrieved by Retrieval Sub
33 308 of a Smart Shuttle 306 as shown in Figure 8. Accordingly,
34 in relation to Figure 1, the above has described an

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1 embodiment of a portion of the drilling assembly being
2 selectively removable from the wellbore without removing the
3 casing portion.
4

5 In a preferred embodiment of the invention described
6 herein, a drilling assembly comprises at least the following
7 fundamental elements: (a) a drill bit; (b) a portion of the
8 drilling assembly that is selectively removable from the
9 wellbore without removing the casing; and (c) mechanical
10 means connecting the drill bit to the selectively removable
11 portion of the drilling assembly. This is an example of a
12 "drilling assembly means". During drilling, measurements are
13 taken by geophysical measurement means and drilling assembly
14 means are used to cause the wellbore to be drilled. In a
15 preferred embodiment herein, the geophysical measurement
16 means are not a portion of the drilling assembly means.
17 The word "selectively" means that the portion of the drilling
18 assembly may be removed at will, and other objects may be
19 removed from the wellbore at different times (such as a
20 logging tool or other geophysical measurement means). In
21 a preferred embodiment of the invention, a logging tool or
22 other geophysical measurement means removed from the well is
23 not a portion of the drilling assembly selectively removed
24 from the well. In this embodiment, removing any drill bit
25 from the well is not an example of a selectively removable
26 portion of a drilling assembly because the drilling assembly
27 must be physically attached to a drill bit. The preferred
28 embodiment described by elements (a), (b), and (c) may be
29 succinctly described as "drilling assembly means having
30 selectively removable portion means". Such means allow the
31 well to be drilled faster and more economically.
32

33 As another preferred embodiment, the pump-down wiper
34 plugs and the pump-down one-way valves may also be removed

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1 from the wellbore after they are cemented in place using
2 analogous techniques that are described in Lesson 8 of the
3 series entitled "Well Servicing and Workover", previously
4 incorporated by reference within the '521 patent, with an
5 overshoot tool of the variety shown in Figure 30 on page 22.
6 Accordingly, in relation to Figure 1, the above has described
7 an embodiment of a portion of the drilling assembly being
8 selectively removable from the wellbore without removing the
9 casing portion.

10
11 Figure 1 shows an apparatus for drilling a wellbore.
12 In relation to Figure 1, and to Figures 1A, 1B, and 1C,
13 element 46 has been previously described above as showing a
14 drill string having a casing portion for lining the wellbore.
15 Figure 1, and Figures 1A, 1B, and 1C, have previously been
16 described above as showing a drilling assembly operatively
17 connected to the drill string and having an earth removal
18 member.

19
20 Accordingly, Figure 1, and Figures 1A, 1B, and 1C,
21 show a preferred embodiment of the invention that is an
22 apparatus for drilling a wellbore comprising: a drill string
23 having a casing portion for lining the wellbore; and a
24 drilling assembly operatively connected to the drill string
25 and having an earth removal member; a portion of the drilling
26 assembly being selectively removable from the wellbore
27 without removing the casing portion.

28
29 Another preferred embodiment of the invention is the
30 apparatus in the previous paragraph further comprising a
31 latching float collar valve means which, following removal of
32 the portion of the drilling assembly from the wellbore,
33 is pumped from the surface of the earth through the drill
34

1 string with drilling mud so as to seat the latching float
2 collar valve means above the earth removal member.

3
4 Figures 1, 1A, 1B, and 1C also show an embodiment of
5 an apparatus for drilling a wellbore comprising: a drill
6 string having a casing portion for lining the wellbore; and a
7 drilling assembly selectively connected to the drill string
8 and having an earth removal member.

9
10 Accordingly, a preferred embodiment of the invention is
11 a method of making a cased wellbore comprising assembling a
12 lower segment of a drill string comprising in sequence from
13 top to bottom a first hollow segment of drill pipe, a
14 drilling assembly means having a selectively removable
15 portion and a rotary drill bit, the rotary drill bit having
16 at least one mud passage for passing drilling mud from the
17 interior of the drill string to the outside of the drill
18 string; and after the predetermined depth is reached,
19 retrieving the selectively removable portion of the drilling
20 assembly from the wellbore, and pumping a latching float
21 collar valve means down the interior of the drill string with
22 drilling mud until it seats into place within the drilling
23 assembly means.

24
25 In accordance with the above, a preferred embodiment
26 of the invention is a rotary drilling apparatus to drill a
27 borehole into the earth comprising a hollow drill string
28 possessing a drilling assembly means having a selectively
29 removable portion and a rotary drill bit, the rotary drill
30 bit having at least one mud passage for passing the drilling
31 mud from within the hollow drill string to the borehole, a
32 source of drilling mud, a source of cement, and at least one
33 latching float collar valve means whereby, after the total
34 depth of the borehole is reached, and after retrieving the

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1 removable portion from the wellbore, the latching float
2 collar valve means is pumped with the drilling mud into place
3 above the rotary drill bit to install the latching float
4 collar means within the hollow drill string above the rotary
5 drill bit that is used to cement the drill string and rotary
6 drill bit into the earth during one pass into the formation
7 of the drill string to make a steel cased well.

8
9 In view of the above, another preferred embodiment of
10 the invention is a method of drilling a well from the surface
11 of the earth and cementing a drill string into place within a
12 wellbore to make a cased well during one pass into formation
13 using an apparatus comprising at least a hollow drill string
14 possessing a drilling assembly means having a selectively
15 removable portion and a rotary drill bit, the drill bit having
16 at least one mud passage to convey drilling mud from the
17 interior of the drill string to the wellbore, a source of
18 drilling mud, a source of cement, and at least one latching
19 float collar valve assembly means, using at least the
20 following steps: (a) after the total depth of the borehole
21 is reached, retrieving the retrievable portion from the
22 wellbore; (b) thereafter pumping the latching float collar
23 valve means from the surface of the earth through the hollow
24 drill string with drilling mud so as to seat the latching
25 float collar valve means above the drill bit; and (c)
26 thereafter pumping cement through the seated latching float
27 collar valve means to cement the drill string and rotary
28 drill bit into place within the wellbore.

29
30 Another preferred embodiment of the invention provides a
31 float and float collar valve assembly permanently installed
32 within the Latching Subassembly at the beginning of the
33 drilling operations. However, such a preferred embodiment
34 has the disadvantage that drilling mud passing by the float

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1 and the float collar valve assembly during normal drilling
2 operations could subject the mutually sealing surfaces to
3 potential wear. Nevertheless, a float collar valve assembly
4 can be permanently installed above the drill bit before the
5 drill bit enters the well.

6 7 8 Permanently Installed One-Way Valve 9

10 Figure 2 shows another preferred embodiment of the
11 invention that has such a float collar valve assembly
12 permanently installed above the drill bit before the drill
13 bit enters the well. Figure 2 shows many elements common to
14 Figure 1. The Permanently Installed Float Collar Valve
15 Assembly 76, hereinafter abbreviated as the "PIFCVA", is
16 installed into the drill string on the surface of the earth
17 before the drill bit enters the well. On the surface, the
18 threads 16 on the rotary drill bit 6 are screwed into the
19 lower female threads 78 of the PIFCVA. The bottom male
20 threads of the drill pipe 48 are screwed into the upper
21 female threads 80 of the PIFCVA. The PIFCVA Latching Sub
22 Recession 82 is similar in nature and function to element 60
23 in Figure 1. The fluids flowing thorough the standard water
24 passage 14 of the drill bit flow through PIFCVA Guide Channel
25 84. The PIFCVA Float 86 has a Hardened Hemispherical Surface
26 88 that seats against the hardened PIFCVA Float Seating
27 Surface 90 under the force PIFCVA Spring 92. Surfaces 88 and
28 90 may be fabricated from very hard materials such as
29 tungsten carbide. Alternatively, any hardening process in
30 the metallurgical arts may be used to harden the surfaces of
31 standard steel parts to make suitable hardened surfaces 88
32 and 90. The lower surfaces of the PIFCVA Spring 92 seat
33 against the upper portion of the PIFCVA Threaded Spacer 94
34 that has PIFCVA Threaded Spacer Passage 96. The PIFCVA

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1 Threaded Spacer 94 has exterior threads that thread into
2 internal threads 100 of the PIFCVA (that is assembled into
3 place within the PIFCVA prior to attachment of the drill bit
4 to the PIFCVA). Surface 102 facing the lower portion of the
5 PIFCVA Guide Channel 84 may also be made from hardened
6 materials, or otherwise surface hardened, so as to prevent
7 wear from the mud flowing through this portion of the channel
8 during drilling.

9
10 Once the PIFCVA is installed into the drill string, then
11 the drill bit is lowered into the well and drilling
12 commenced. Mud pressure from the surface opens PIFCVA Float
13 86. The steps for using the preferred embodiment in Figure 2
14 are slightly different than using that shown in Figure 1.
15 Basically, the "Steps 7 - 11 (Revised)" of the "New Drilling
16 Process" are eliminated because it is not necessary to pump
17 down any type of Latching Float Collar Valve Assembly of the
18 type described in Figure 1. In "Steps 3 - 5 (Revised)" of
19 the "New Drilling Process", it is evident that the PIFCVA is
20 installed into the drill string instead of the Latching
21 Subassembly appropriate for Figure 1. In Steps 12 - 13
22 (Revised) of the "New Drilling Process", it is also evident
23 that the Lower Lobe of the Bottom Wiper Plug 58 latches into
24 place into the PIFCVA Latching Sub Recession 82.

25
26 The PIFCVA installed into the drill string is another
27 example of a one-way cement valve means installed near the
28 drill bit to be used during one pass drilling of the well.
29 Here, the term "near" shall mean within 500 feet of the drill
30 bit. Consequently, Figure 2 describes a rotary drilling
31 apparatus to drill a borehole into the earth comprising a
32 drill string attached to a rotary drill bit and one-way
33 cement valve means installed near the drill bit to cement the
34 drill string and rotary drill bit into the earth to make a

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1 steel cased well. Here, in this preferred embodiment, the
2 method of drilling the borehole is implemented with a rotary
3 drill bit having mud passages to pass mud into the borehole
4 from within a steel drill string that includes at least one
5 step that passes cement through such mud passages to cement
6 the drill string into place to make a steel cased well.

7
8 The drill bits described in Figure 1 and Figure 2 are
9 milled steel toothed roller cone bits. However, any rotary
10 bit can be used with the invention. A tungsten carbide
11 insert roller cone bit can be used. Any type of diamond bit
12 or drag bit can be used. The invention may be used with any,
13 drill bit described in Ref. 3 above that possesses mud
14 passages, waterpassages, or passages for gas. Any type of
15 rotary drill bit can be used possessing such passageways.
16 Similarly, any type of bit whatsoever that utilizes any fluid
17 or gas that passes through passageways in the bit can be used
18 whether or not the bit rotates.

19
20 As another example of "...any type of bit whatsoever..."
21 described in the previous sentence, a new type of drill bit
22 invented by the inventor of this application can be used
23 for the purposes herein that is disclosed in U.S. Patent
24 No. 5,615,747, that is entitled "Monolithic Self Sharpening
25 Rotary Drill Bit Having Tungsten Carbide Rods Cast in Steel
26 Alloys", that issued on April 1, 1997 (hereinafter
27 Vail{747}), an entire copy of which is incorporated herein
28 by reference. That new type of drill bit is further
29 described in a Continuing Application of Vail{747} that is
30 now U.S. Patent No. 5,836,409, that is also entitled
31 "Monolithic Self Sharpening Rotary Drill Bit Having Tungsten
32 Carbide Rods Cast in Steel Alloys", that issued on the date
33 of November 17, 1998 (hereinafter Vail{409}), an entire copy
34 of which is incorporated herein by reference. That new type

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1 of drill bit is further described in a Continuation-in-Part
2 Application of Vail{409} that is Serial No. 09/192,248, that
3 has the filing date of 11/16/1998, that is now U.S. Patent
4 No. 6,547,017, which issued on 4/15/2003 (hereinafter
5 Vail{017}) which is entitled "Rotary Drill Bit Compensating
6 for Changes in Hardness of Geological Formations", an entire
7 copy of which is incorporated herein by reference. That new
8 type of drill bit is further described in a Continuation in
9 Part Application of Vail{017} that is Serial No. 10/413,101,
10 having the filing date of 4/14/2003, that is also entitled
11 "Rotary Drill Bit Compensating for Changes in Hardness of
12 Geological Formations". As yet another example of "..any
13 type of bit whatsoever.." described in the last sentence of
14 the previous paragraph, Figure 3 shows the use of the
15 invention using coiled-tubing drilling techniques.

16 17 18 Coiled Tubing Drilling

19
20 Figure 3 shows another preferred embodiment of the
21 invention that is used for certain types of coiled-tubing
22 drilling applications. Figure 3 shows many elements common
23 to Figure 1. It is explicitly stated at this point that all
24 the standard coiled-tubing drilling arts now practiced in the
25 industry are incorporated herein by reference. Not shown in
26 Figure 3 is the coiled tubing drilling rig on the surface of
27 the earth having among other features, the coiled tubing
28 unit, a source of mud, mud pump, etc. In Figure 3, the well
29 has been drilled. This well can be: (a) a freshly drilled
30 well; or (b) a well that has been sidetracked to a geological
31 formation from within a casing string that is an existing
32 cased well during standard re-entry applications; or
33 (c) a well that has been sidetracked from within a tubing
34 string that is in turn suspended within a casing string in

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1 an existing well during certain other types of re-entry
2 applications. Therefore, regardless of how drilling is
3 initially conducted, in an open hole, or from within a cased
4 well that may or may not have a tubing string, the apparatus
5 shown in Figure 3 drills a borehole 2 through the earth
6 including through geological formation 4.

7
8 Before drilling commences, the lower end of the coiled
9 tubing 104 is attached to the Latching Subassembly 18. The
10 bottom male threads of the coiled tubing 106 thread into the
11 female threads of the Latching Subassembly 50.

12
13 The top male threads 108 of the Stationary Mud Motor
14 Assembly 110 are screwed into the lower female threads 112 of
15 Latching Subassembly 18. Mud under pressure flowing through
16 channel 113 causes the Rotating Mud Motor Assembly 114 to
17 rotate in the well. The Rotating Mud Motor Assembly 114
18 causes the Mud Motor Drill Bit Body 116 to rotate. In a
19 preferred embodiment, elements 110, 114 and 116 are elements
20 comprising a mud-motor drilling apparatus. That Mud Motor
21 Drill Bit Body holds in place milled steel roller cones 118,
22 120, and 122 (not shown for simplicity). A standard water
23 passage 124 is shown through the Mud Motor Drill Bit Body.
24 During drilling operations, as mud is pumped down from the
25 surface, the Rotating Mud Motor Assembly 114 rotates causing
26 the drilling action in the well. It should be noted that any
27 fluid pumped from the surface under sufficient pressure that
28 passes through channel 113 goes through the mud motor turbine
29 (not shown) that causes the rotation of the Mud Motor Drill
30 Bit Body and then flows through standard water passage 124
31 and finally into the well.

32
33 The steps for using the preferred embodiment in Figure 3
34 are slightly different than using that shown in Figure 1. In

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1 drilling an open hole, "Steps 3 - 5 (Revised)" of the "New
2 Drilling Process" must be revised here to site attachment of
3 the Latching Subassembly to one end of the coiled tubing and
4 to site that standard coiled tubing drilling methods are
5 employed. The coiled tubing can be on the coiled tubing unit
6 at the surface for this step or the tubing can be installed
7 into a wellhead on the surface for this step. In "Step 6
8 (Revised)" of the "New Drilling Process", measurements are to
9 be performed from within the coiled tubing when it is
10 disposed in the well. In "Steps 12 -13 (Revised)" of the
11 "New Drilling Process", the Bottom Wiper Plug and the Top
12 Wiper Plug are introduced into the upper end of the coiled
13 tubing at the surface. The coiled tubing can be on the
14 coiled tubing unit at the surface for these steps or the
15 tubing can be installed into a wellhead on the surface for
16 these steps. In sidetracking from within an existing casing,
17 in addition to the above steps, it is also necessary to lower
18 the coiled tubing drilling apparatus into the cased well and
19 drill through the casing into the adjacent geological
20 formation at some predetermined depth. In sidetracking from
21 within an existing tubing string suspended within an existing
22 casing string, it is also necessary to lower the coiled
23 tubing drilling apparatus into the tubing string and then
24 drill through the tubing string and then drill through the
25 casing into the adjacent geological formation at some
26 predetermined depth.

27
28 Therefore, Figure 3 shows a tubing conveyed mud motor
29 drill bit apparatus to drill a borehole into the earth having
30 a tubing attached to a mud motor driven rotary drill bit. A
31 one-way cement valve means installed above the drill bit is
32 used to cement the drill string and rotary drill bit into the
33 earth to make a tubing encased well. The tubing conveyed mud
34 motor drill bit apparatus is also called a tubing conveyed

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1 mud motor drilling apparatus, that is also called a tubing
2 conveyed mud motor driven rotary drill bit apparatus. Put
3 another way, Figure 3 shows a section view of a coiled tubing
4 conveyed mud motor driven rotary drill bit apparatus in the
5 process of being cemented into place during one drilling pass
6 into formation. This apparatus is cemented into place by
7 using a Latching Float Collar Valve Assembly that has been
8 pumped into place above the rotary drill bit. Methods of
9 operating the tubing conveyed mud motor drilling apparatus in
10 Figure 3 include a method of drilling a borehole with a
11 coiled tubing conveyed mud motor driven rotary drill bit
12 having mud passages to pass mud into the borehole from within
13 the tubing that includes at least one step that passes cement
14 through the mud passages to cement the tubing into place to
15 make a tubing encased well.

16
17 In the "New Drilling Process", Step 14 is to be
18 repeated, and that step is quoted in part in the following
19 paragraph as follows:

20
21 'Step 14. Follow normal "final completion operations"
22 that include installing the tubing with packers and
23 perforating the casing near the producing zones. For a
24 description of such normal final completion operations,
25 please refer to the book entitled "Well Completion
26 Methods", Well Servicing and Workover, Lesson 4, from
27 the series entitled "Lessons in Well Servicing and
28 Workover", Petroleum Extension Service, The University
29 of Texas at Austin, Austin, Texas, 1971 (hereinafter
30 defined as "Ref. 2"), an entire copy of which is
31 incorporated herein by reference. All of the individual
32 definitions of words and phrases in the Glossary of
33 Ref. 2 are also explicitly and separately incorporated
34 herein in their entirety by reference. Other methods of

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1 completing the well are described therein that shall,
2 for the purposes of this application herein, also be
3 called "final completion operations".'
4

5 With reference to the last sentence above, there are
6 indeed many 'Other methods of completing the well that for
7 the purposes of this application herein, also be called
8 "final completion operations"'. For example, Ref. 2 on
9 pages 10-11 describe "Open-Hole Completions". Ref. 2 on
10 pages 13-17 describe "Liner Completions". Ref. 2 on pages
11 17-30 describe "Perforated Casing Completions" that also
12 includes descriptions of centralizers, squeeze cementing,
13 single zone completions, multiple zone completions,
14 tubingless completions, multiple tubingless completions, and
15 deep well liner completions among other topics.
16

17 Similar topics are also discussed in a previously
18 referenced book entitled "Testing and Completing",
19 Unit II, Lesson 5, Second Edition, of the Rotary Drilling
20 Series, Petroleum Extension Service, The University of Texas
21 at Austin, Austin, Texas, 1983 (hereinafter defined as
22 "Ref. 4"), an entire copy of which is incorporated herein
23 by reference. All of the individual definitions of words
24 and phrases in the Glossary of Ref. 1 are also explicitly
25 and separately incorporated herein in their entirety by
26 reference.
27

28 For example, on page 20 of Ref. 4, the topic "Completion
29 Design" is discussed. Under this topic are described various
30 different "Completion Methods". Page 21 of Ref. 4 describes
31 "Open-hole completions". Under the topic of "Perforated
32 completion" on pages 20-22, are described both standard
33 cementing completions and gravel completions using slotted
34 liners.

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Well Completions with Slurry Materials

Standard cementing completions are described above in the new "New Drilling Process". However, it is evident that any slurry like material or "slurry material" that flows under pressure, and behaves like a multicomponent viscous liquid like material, can be used instead of "cement" in the "New Drilling Process". In particular, instead of "cement", water, gravel, or any other material can be used provided it flows through pipes under suitable pressure.

At this point, it is useful to review several definitions that are routinely used in the industry. First, the glossary of Ref. 4 defines several terms of interest.

The Glossary of Ref. 4 defines the term "to complete a well" to be the following: "to finish work on a well and bring it to productive status. See well completion."

The Glossary of Ref. 4 defines the term "well completion" to be the following: "1. the activities and methods of preparing a well for the production of oil and gas; the method by which one or more flow paths for hydrocarbons is established between the reservoir and the surface. 2. the systems of tubulars, packers, and other tools installed beneath the wellhead in the production casing, that is, the tool assembly that provides the hydrocarbon flow path or paths." To be precise for the purposes herein, the term "completing a well" or the term "completing the well" are each separately equivalent to performing all the necessary steps for a "well completion".

The Glossary of Ref. 4 defines the term "gravel" to be the following: "in gravel packing, sand or glass beads of

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1 uniform size and roundness."

2
3 The Glossary of Ref. 4 defines the term "gravel packing"
4 to be the following: "a method of well completion in which a
5 slotted or perforated liner, often wire-wrapper, is placed in
6 the well and surrounded by gravel. If open-hole, the well is
7 sometimes enlarged by underreaming at the point where the
8 gravel is packed. The mass of gravel excludes sand from the
9 wellbore but allows continued production."

10
11 Other pertinent terms are defined in Ref. 1.

12
13 The Glossary of Ref. 1 defines the term "cement" to be
14 the following: "a powder, consisting of alumina, silica,
15 lime, and other substances that hardens when mixed with
16 water. Extensively used in the oil industry to bond casing
17 to walls of the wellbore."

18
19 The Glossary of Ref. 1 defines the term "cement clinker"
20 to be the following: "a substance formed by melting ground
21 limestone, clay or shale, and iron ore in a kiln. Cement
22 clinker is ground into a powdery mixture and combined with
23 small amounts of gypsum or other materials to form a
24 cement".

25
26 The Glossary of Ref. 1 defines the term "slurry" to be
27 the following: "a plastic mixture of cement and water that is
28 pumped into a well to harden; there it supports the casing
29 and provides a seal in the wellbore to prevent migration of
30 underground fluids."

31
32 The Glossary of Ref. 1 defines the term "casing" as
33 is typically used in the oil and gas industries to be the
34 following: "steel pipe placed in an oil or gas well as

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1 drilling progresses to prevent the wall of the hole from
2 caving in during drilling, to prevent seepage of fluids, and
3 to provide a means of extracting petroleum if the well is
4 productive". Of course, in light of the invention herein,
5 the "drill pipe" becomes the "casing", so the above
6 definition needs modification under certain usages herein.
7

8 U.S. Patent No. 4,883,125, that issued on 11/28/1994,
9 that is entitled "Cementing Oil and Gas Wells Using Converted
10 Drilling Fluid", an entire copy of which is incorporated
11 herein by reference, describes using "a quantity of drilling
12 fluid mixed with a cement material and a dispersant such as a
13 sulfonated styrene copolymer with or without an organic
14 acid". Such a "cement and copolymer mixture" is yet another
15 example of a "slurry material" for the purposes herein.
16

17 U.S. Patent No. 5,343,951, that issued on 9/6/1994,
18 that is entitled "Drilling and Cementing Slim Hole Wells",
19 an entire copy of which is incorporated herein by reference,
20 describes "a drilling fluid comprising blast furnace slag and
21 water" that is subjected thereafter to an activator that is
22 "generally, an alkaline material and additional blast furnace
23 slag, to produce a cementitious slurry which is passed down a
24 casing and up into an annulus to effect primary cementing."
25 Such an "blast furnace slag mixture" is yet another example
26 of a "slurry material" for the purposes herein.
27

28 Therefore, and in summary, a "slurry material" may be
29 any one, or more, of at least the following substances as
30 rigorously defined above: cement, gravel, water, cement
31 clinker, a "slurry" as rigorously defined above, a "cement
32 and copolymer mixture", a "blast furnace slag mixture",
33 and/or any mixture thereof. Virtually any known substance
34

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1 that flows under sufficient pressure may be defined the
2 purposes herein as a "slurry material".
3

4 Therefore, in view of the above definitions, it is now
5 evident that the "New Drilling Process" may be performed with
6 any "slurry material". The slurry material may be used in
7 the "New Drilling Process" for open-hole well completions;
8 for typical cemented well completions having perforated
9 casings; and for gravel well completions having perforated
10 casings; and for any other such well completions.
11

12 Accordingly, a preferred embodiment of the invention is
13 the method of drilling a borehole with a rotary drill bit
14 having mud passages for passing mud into the borehole from
15 within a steel drill string that includes at least the one
16 step of passing a slurry material through those mud passages
17 for the purpose of completing the well and leaving the drill
18 string in place to make a steel cased well.
19

20 Further, another preferred embodiment of the inventions
21 is the method of drilling a borehole into a geological
22 formation with a rotary drill bit having mud passages for
23 passing mud into the borehole from within a steel drill
24 string that includes at least one step of passing a slurry
25 material through the mud passages for the purpose of
26 completing the well and leaving the drill string in place
27 following the well completion to make a steel cased well
28 during one drilling pass into the geological formation.
29

30 Yet further, another preferred embodiment of the
31 invention is a method of drilling a borehole with a coiled
32 tubing conveyed mud motor driven rotary drill bit having mud
33 passages for passing mud into the borehole from within the
34 tubing that includes at the least one step of passing a

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1 slurry material through the mud passages for the purpose of
2 completing the well and leaving the tubing in place to make
3 a tubing encased well.

4
5 And further, yet another preferred embodiment of the
6 invention is a method of drilling a borehole into a
7 geological formation with a coiled tubing conveyed mud motor
8 driven rotary drill bit having mud passages for passing mud
9 into the borehole from within the tubing that includes at
10 least the one step of passing a slurry material through the
11 mud passages for the purpose of completing the well and
12 leaving the tubing in place following the well completion to
13 make a tubing encased well during one drilling pass into the
14 geological formation.

15
16 Yet further, another preferred embodiment of the
17 invention is a method of drilling a borehole with a rotary
18 drill bit having mud passages for passing mud into the
19 borehole from within a steel drill string that includes at
20 least steps of: attaching a drill bit to the drill string;
21 drilling the well with the rotary drill bit to a desired
22 depth; and completing the well with the drill bit attached
23 to the drill string to make a steel cased well.

24
25 Still further, another preferred embodiment of the
26 invention is a method of drilling a borehole with a coiled
27 tubing conveyed mud motor driven rotary drill bit having mud
28 passages for passing mud into the borehole from within the
29 tubing that includes at least the steps of: attaching the mud
30 motor driven rotary drill bit to the coiled tubing; drilling
31 the well with the tubing conveyed mud motor driven rotary
32 drill bit to a desired depth; and completing the well with
33 the mud motor driven rotary drill bit attached to the drill
34 string to make a steel cased well.

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1 And still further, another preferred embodiment of the
2 invention is the method of one pass drilling of a geological
3 formation of interest to produce hydrocarbons comprising at
4 least the following steps: attaching a drill bit to a casing
5 string; drilling a borehole into the earth to a geological
6 formation of interest; providing a pathway for fluids to
7 enter into the casing from the geological formation of
8 interest; completing the well adjacent to the formation
9 of interest with at least one of cement, gravel, chemical
10 ingredients, mud; and passing the hydrocarbons through the
11 casing to the surface of the earth while the drill
12 bit remains attached to the casing.
13

14 The term "extended reach boreholes" is a term often used
15 in the oil and gas industry. For example, this term is used
16 in U.S. Patent No. 5,343,950, that issued September 6, 1994,
17 having the Assignee of Shell Oil Company, that is entitled
18 "Drilling and Cementing Extended Reach Boreholes". An entire
19 copy of U.S. Patent No. 5,343,950 is incorporated herein by
20 reference. This term can be applied to very deep wells, but
21 most often is used to describe those wells typically drilled
22 and completed from offshore platforms. To be more explicit,
23 those "extended reach boreholes" that are completed from
24 offshore platforms may also be called for the purposes herein
25 "extended reach lateral boreholes". Often, this particular
26 term, "extended reach lateral boreholes", implies that
27 substantial portions of the wells have been completed in one
28 more or less "horizontal formation". The term "extended
29 reach lateral borehole" is equivalent to the term "extended
30 reach lateral wellbore" for the purposes herein. The term
31 "extended reach borehole" is equivalent to the term "extended
32 reach wellbore" for the purposes herein. The invention
33 herein is particularly useful to drill and complete "extended
34 reach wellbores" and "extend reach lateral wellbores".

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1 Therefore, the preferred embodiments above generally
2 disclose the one pass drilling and completion of wellbores
3 with drill bit attached to drill string to make cased
4 wellbores to produce hydrocarbons. The preferred embodiments
5 above are also particularly useful to drill and complete
6 "extended reach wellbores" and "extended reach lateral
7 wellbores".
8

9 For methods and apparatus particularly suitable for
10 the one pass drilling and completion of extended reach
11 lateral wellbores please refer to **Figure 4**. Figure 4 shows
12 another preferred embodiment of the invention that is closely
13 related to Figure 3. Those elements numbered in sequence
14 through element number 124 have already been defined
15 previously. In Figure 4, the previous single "Top Wiper
16 Plug 64" in Figures 1, 2, and 3 has been removed, and
17 instead, it has been replaced with two new wiper plugs,
18 respectively called "Wiper Plug A" and "Wiper Plug B".
19 Wiper Plug A is labeled with numeral 126, and Wiper Plug A
20 has a bottom surface that is defined as the Bottom Surface of
21 Wiper Plug A that is numeral 128. The Upper Plug Seal of
22 Wiper Plug A is labeled with numeral 130, and as it is shown
23 in Figure 4, is not ruptured. The Upper Plug Seal of Wiper
24 Plug A that is numeral 130 functions analogously to
25 elements 54 and 56 of the Upper Seal of the Bottom
26 Wiper Plug 52 that are shown in ruptured conditions in
27 Figures 1, 2 and 3.
28

29 In Figure 4, Wiper Plug B is labeled with numeral 132.
30 It has a lower surface that is called the "Bottom Surface of
31 Wiper Plug B" that is labeled with numeral 134. Wiper Plug A
32 and Wiper Plug B are introduced separately into the interior
33 of the tubing to pass multiple slurry materials into the
34 wellbore to complete the well.

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1 Using analogous methods described above in relation to
2 Figures 1, 2, and 3, water 136 in the tubing is used to push
3 on Wiper Plug B (element 132), that in turn pushes on cement
4 138 in the tubing, that in turn is used to push on gravel
5 140, that in turn pushes on the Float 32, that in turn
6 forces gravel into the wellbore past Float 32, that in turn
7 forces mud 142 upward in the annulus of the wellbore. An
8 explicit boundary between the mud and gravel is shown in the
9 annulus of the wellbore in Figure 4, and that boundary is
10 labeled with numeral 144.

11
12 After the Bottom Surface of Wiper Plug A that is
13 element 128 positively "bottoms out" on the Top Surface 74 of
14 the Bottom Wiper Plug, then a predetermined amount of gravel
15 has been injected into the wellbore forcing mud 142 upward in
16 the annulus. Thereafter, forcing additional water 136 into
17 the tubing will cause the Upper Plug Seal of Wiper Plug A
18 (element 130) to rupture, thereby forcing cement 138 to flow
19 toward the Float 32. Forcing yet additional water 136 into
20 the tubing will in turn cause the Bottom Surface of Wiper
21 Plug B 134 to "bottom out" on the Top Surface of Wiper Plug A
22 that is labeled with numeral 146. At this point in the
23 process, mud has been forced upward in the annulus of
24 wellbore by gravel. The purpose of this process is to have
25 suitable amounts of gravel and cement placed sequentially
26 into the annulus between the wellbore for the completion of
27 the tubing encased well and for the ultimate production of
28 oil and gas from the completed well. This process is
29 particularly useful for the drilling and completion of
30 extended reach lateral wellbores with a tubing conveyed mud
31 motor drilling apparatus to make tubing encased wellbores for
32 the production of oil and gas.

33
34
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1 It is clear that Figure 1 could be modified with
2 suitable Wiper Plugs A and B as described above in relation
3 to Figure 4. Put simply, in light of the disclosure above,
4 Figure 4 could be suitably altered to show a rotary drill bit
5 attached to lengths of casing. However, in an effort to be
6 brief, that detail will not be further described. Instead,
7 Figure 5 shows one "snapshot" in the one pass drilling and
8 completion of an extended reach lateral wellbore with drill
9 bit attached to the drill string that is used to produce
10 hydrocarbons from offshore platforms. This figure was
11 substantially disclosed in U.S. Disclosure Document
12 No. 452648 that was filed on March 5, 1999.

13 14 15 Extended Reach Lateral Wellbores 16

17 In Figure 5, an offshore platform 148 has a rotary
18 drilling rig 150 surrounded by ocean 152 that is attached to
19 the bottom of the sea 154. Riser 156 is attached to blowout
20 preventer 158. Surface casing 160 is cemented into place
21 with cement 162. Other conductor pipe, surface casing,
22 intermediate casings, liner strings, or other pipes may be
23 present, but are not shown for simplicity. The drilling rig
24 150 has all typical components of a normal drilling rig as
25 defined in the figure entitled "The Rig and its Components"
26 opposite of page 1 of the book entitled "The Rotary Rig
27 and Its Components", Third Edition, Unit I, Lesson 1, that
28 is part of the "Rotary Drilling Series" published by the
29 Petroleum Extension Service, Division of Continuing
30 Education, The University of Texas at Austin, Austin,
31 Texas, 1980, 39 pages, and entire copy of which is
32 incorporated herein by reference.

33
34
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1 Figure 5 shows that oil bearing formation 164 has been
2 drilled into with rotary drill bit 166. The oil bearing
3 formation is in the earth below the ocean bottom. Drill bit
4 166 is attached to a "Completion Sub" having the appropriate
5 float collar valve assembly, or other suitable float collar
6 device, or which has one or more suitable latch recessions
7 such as element 24 in Figure 1 for the purposes previously
8 described, and which has other suitable completion devices as
9 required that are shown in Figures 1, 2, 3, and 4. That
10 "Completion Sub" is labeled with numeral 168 in Figure 5.
11 Completion Sub 168 is in turn attached to many lengths of
12 drill pipe, or casing as appropriate, one of which is labeled
13 with numeral 170 in Figure 5. The drill pipe is supported by
14 usual drilling apparatus provided by the drilling rig. Such
15 drilling apparatus provides an upward force at the surface
16 labeled with legend "F" in Figure 5, and the drill string is
17 turned with torque provided by the drilling apparatus of the
18 drilling rig, and that torque is figuratively labeled with
19 the legend "T" in Figure 5.

20
21 The previously described methods and apparatus were used
22 to first, in sequence, force gravel 172 in the portion of the
23 oil bearing formation 164 having producible hydrocarbons.
24 If required, a cement plug formed by a "squeeze job" is
25 figuratively shown by numeral 174 in Figure 5 to prevent
26 contamination of the gravel. Alternatively, an external
27 casing packer, or other types of controllable packer means
28 may be used for such purposes as previously disclosed by
29 applicant in U.S. Disclosure Document No. 445686, filed on
30 October 11, 1998. Yet further, the cement plug 174 can be
31 pumped into place ahead of the gravel using the above
32 procedures using yet another wiper plug as may be required.

33
34
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1 The cement 176 introduced into the borehole through the
2 mud passages of the drill bit using the above defined methods
3 and apparatus provides a seal near the drill bit, among other
4 locations, that is desirable under certain situations.
5

6 Slots in the drill pipe have been opened after the drill
7 pipe reached final depth. The slots can be milled with a
8 special milling cutter having thin rotating blades that are
9 pushed against the inside of the pipe. As an alternative,
10 standard perforations may be fabricated in the pipe using
11 standard perforation guns of the type typically used in the
12 industry. Yet further, special types of expandable pipe may
13 be manufactured that when pressurized from the inside against
14 a cement plug near the drill bit or against a solid strong
15 wiper plug, or against a bridge plug, suitable slots are
16 forced open. Or, different materials may be used in solid
17 slots along the length of steel pipe when the pipe is
18 fabricated that can be etched out with acid during the well
19 completion process to make the slots and otherwise leaving
20 the remaining steel pipe in place. Accordingly, there are
21 many ways to make the required slots. One such slot is
22 labeled with numeral 178 in Figure 5, and there are many
23 such slots.
24

25 Therefore, hydrocarbons in zone 164 are produced through
26 gravel 172 that flows through slots 178 and into the interior
27 of the drill pipe to implement the one pass drilling and
28 completion of an extended reach lateral wellbore with drill
29 bit attached to drill string to produce hydrocarbons from an
30 offshore platform. For the purposes of this preferred
31 embodiment, such a completion is called a "gravel pack"
32 completion, whether or not cement 174 or cement 176
33 are introduced into the wellbore.
34

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1 It should be noted that in some embodiments, cement is
2 not necessarily needed, and the formations may be "gravel
3 pack" completed, or may be open-hole completed. In some
4 situations, the float, or the one-way valve, need not be
5 required depending upon the pressures in the formation.
6

7 Figure 5 also shows a zone that has been cemented shut
8 with a "squeeze job", a term known in the industry
9 representing perforating and then forcing cement into the
10 annulus using suitable packers in order to cement certain
11 formations. This particular cement introduced into the
12 annulus of the wellbore in Figure 5 is shown as element 180.
13 Such additional cementations may be needed to isolate certain
14 formations as is typically done in the industry. As a final
15 comment, the annulus 182 of the open hole 184 may otherwise
16 be completed using typical well completion procedures in the
17 oil and gas industries.
18

19 Therefore, Figure 5 and the above description discloses
20 a preferred method of drilling an extended reach lateral
21 wellbore from an offshore platform with a rotary drill bit
22 having mud passages for passing mud into the borehole from
23 within a steel drill string that includes at least one step
24 of passing a slurry material through the mud passages for the
25 purpose of completing the well and leaving the drill string
26 in place to make a steel cased well to produce hydrocarbons
27 from the offshore platform. As stated before, the term
28 "slurry material" may be any one, or more, of at least the
29 following substances: cement, gravel, water, "cement
30 clinker", a "cement and copolymer mixture", a "blast furnace
31 slag mixture", and/or any mixture thereof; or any known
32 substance that flows under sufficient pressure.
33
34

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1 Further, the above provides disclosure of a method of
2 drilling an extended reach lateral wellbore from an offshore
3 platform with a rotary drill bit having mud passages for
4 passing mud into the borehole from within a steel drill
5 string that includes at least the steps of passing
6 sequentially in order a first slurry material and then a
7 second slurry material through the mud passages for the
8 purpose of completing the well and leaving the drill string
9 in place to make a steel cased well to produce hydrocarbons
10 from offshore platforms.

11
12 Yet another preferred embodiment of the invention
13 provides a method of drilling an extended reach lateral
14 wellbore from an offshore platform with a rotary drill bit
15 having mud passages for passing mud into the borehole from
16 within a steel drill string that includes at least the step
17 of passing a multiplicity of slurry materials through the mud
18 passages for the purpose of completing the well and leaving
19 the drill string in place to make a steel cased well to
20 produce hydrocarbons from the offshore platform.

21
22 It is evident from the disclosure in Figures 3 and 4,
23 that a tubing conveyed mud motor drilling apparatus
24 may replace the rotary drilling apparatus in Figure 5.
25 Consequently, the above has provided another preferred
26 embodiment of the invention that discloses the method of
27 drilling an extended reach lateral wellbore from an offshore
28 platform with a coiled tubing conveyed mud motor driven
29 rotary drill bit having mud passages for passing mud into the
30 borehole from within the tubing that includes at least one
31 step of passing a slurry material through the mud passages
32 for the purpose of completing the well and leaving the tubing
33 in place to make a tubing encased well to produce
34 hydrocarbons from the offshore platform.

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1 And yet further, another preferred embodiment of the
2 invention provides a method of drilling an extended reach
3 lateral wellbore from an offshore platform with a coiled
4 tubing conveyed mud motor driven rotary drill bit having mud
5 passages for passing mud into the borehole from within the
6 tubing that includes at least the steps of passing
7 sequentially in order a first slurry material and then a
8 second slurry material through the mud passages for the
9 purpose of completing the well and leaving the tubing in
10 place to make a tubing encased well to produce hydrocarbons
11 from the offshore platform.
12

13 And yet another preferred embodiment of the invention
14 discloses passing a multiplicity of slurry materials through
15 the mud passages of the tubing conveyed mud motor driven
16 rotary drill bit to make a tubing encased well to produce
17 hydrocarbons from the offshore platform.
18

19 For the purposes of this disclosure, any reference cited
20 above is incorporated herein in its entirety by reference
21 herein. Further, any document, article, or book cited in any
22 such above defined reference is also incorporated herein in
23 its entirety by reference herein.
24

25 It should also be stated that the invention pertains to
26 any type of drill bit having any conceivable type of passage
27 way for mud that is attached to any conceivable type of drill
28 pipe that drills to a depth in a geological formation wherein
29 the drill bit is thereafter left at the depth when the
30 drilling stops and the well is completed. Any type of
31 drilling apparatus that has at least one passage way for mud
32 that is attached to any type of drill pipe is also an
33 embodiment of this invention, where the drilling apparatus
34 specifically includes any type of rotary drill bit, any type

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1 of mud driven drill bit, any type of hydraulically activated
2 drill bit, or any type of electrically energized drill bit,
3 or any drill bit that is any combination of the above. Any
4 type of drilling apparatus that has at least one passage way
5 for mud that is attached to any type of casing is also an
6 embodiment of this invention, and this includes any metallic
7 casing, any composite casing, and any plastic casing.
8 Any type of drill bit attached to any type of drill pipe, or
9 pipe, made from any material is an embodiment of this
10 invention, where such pipe includes a metallic pipe; a casing
11 string; a casing string with any retrievable drill bit
12 removed from the wellbore; a casing string with any drilling
13 apparatus removed from the wellbore; a casing string with any
14 electrically operated drilling apparatus retrieved from the
15 wellbore; a casing string with any bicenter bit removed from
16 the wellbore; a steel pipe; an expandable pipe; an expandable
17 pipe made from any material; an expandable metallic pipe; an
18 expandable metallic pipe with any retrievable drill bit
19 removed from the wellbore; an expandable metallic pipe with
20 any drilling apparatus removed from the wellbore; an
21 expandable metallic pipe with any electrically operated
22 drilling apparatus retrieved from the wellbore; an expandable
23 metallic pipe with any bicenter bit removed from the
24 wellbore; a plastic pipe; a fiberglass pipe; any type of
25 composite pipe; any composite pipe that encapsulates
26 insulated wires carrying electricity and/or any tubes
27 containing hydraulic fluid; a composite pipe with any
28 retrievable drill bit removed from the wellbore; a composite
29 pipe with any drilling apparatus removed from the wellbore;
30 a composite pipe with any electrically operated drilling
31 apparatus retrieved from the wellbore; a composite pipe with
32 any bicenter bit removed from the wellbore; a drill string;
33 a drill string possessing a drill bit that remains attached
34 to the end of the drill string after completing the wellbore;

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1 a drill string with any retrievable drill bit removed from
2 the wellbore; a drill string with any drilling apparatus
3 removed from the wellbore; a drill string with any
4 electrically operated drilling apparatus retrieved from the
5 wellbore; a drill string with any bicenter bit removed from
6 the wellbore; a coiled tubing; a coiled tubing possessing a
7 mud-motor drilling apparatus that remains attached to the
8 coiled tubing after completing the wellbore; a coiled tubing
9 left in place after any mud-motor drilling apparatus has been
10 removed; a coiled tubing left in place after any electrically
11 operated drilling apparatus has been retrieved from the
12 wellbore; a liner made from any material; a liner with any
13 retrievable drill bit removed from the wellbore; a liner with
14 any liner drilling apparatus removed from the wellbore;
15 a liner with any electrically operated drilling apparatus
16 retrieved from the liner; a liner with any bicenter bit
17 removed from the wellbore; any other pipe made of any
18 material with any type of drilling apparatus removed from the
19 pipe; or any other pipe made of any material with any type of
20 drilling apparatus removed from the wellbore. Any drill bit
21 attached to any drill pipe that remains at depth following
22 well completion is further an embodiment of this invention,
23 and this specifically includes any retractable type drill
24 bit, or retrievable type drill bit, that because of failure,
25 or choice, remains attached to the drill string when the well
26 is completed.

27
28 As had been referenced earlier, the above disclosure
29 related to Figures 1-5 had been substantially repeated herein
30 from Serial No. 09/295,808, now U.S. Patent 6,263,987 B1, and
31 this disclosure is used so that the new preferred embodiments
32 of the invention can be economically described in terms of
33 those figures. It should also be noted that the following
34 disclosure related to Figures 6, 7, 8, 9, 10, 11, 12, 13, 14,

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1 15, 16, 17, and 18 is also substantially repeated herein from
2 Serial No. 09/487,197, now U.S. Patent 6,397,946 B1.

3
4 Before describing those new features, perhaps a bit
5 of nomenclature should be discussed at this point. In
6 various descriptions of preferred embodiments herein
7 described, the inventor frequently uses the designation of
8 "one pass drilling", that is also called "One-Trip-Drilling"
9 for the purposes herein, and otherwise also called
10 "One-Trip-Down-Drilling" for the purposes herein.
11 For the purposes herein, a first definition of the phrases
12 "one pass drilling", "One-Trip-Drilling", and "One-Trip-Down-
13 Drilling" mean the process that results in the last long
14 piece of pipe put in the wellbore to which a drill bit is
15 attached is left in place after total depth is reached, and
16 is completed in place, and oil and gas is ultimately produced
17 from within the wellbore through that long piece of pipe. Of
18 course, other pipes, including risers, conductor pipes,
19 surface casings, intermediate casings, etc., may be present,
20 but the last very long pipe attached to the drill bit that
21 reaches the final depth is left in place and the well is
22 completed using this first definition. This process is
23 directed at dramatically reducing the number of steps to
24 drill and complete oil and gas wells.

25
26 In accordance with the above, a preferred embodiment of
27 the invention is a method of drilling a borehole from an
28 offshore platform with a rotary drill bit having at least one
29 mud passage for passing mud into the borehole from within
30 a steel drill string comprising at least steps of:
31 (a) attaching a drill bit to the drill string; (b) drilling
32 the well from the offshore platform with the rotary drill bit
33 to a desired depth; and (c) completing the well with the
34 drill bit attached to the drill string to make a steel cased

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1 well. Such a method applies wherein the borehole is an
2 extended reach wellbore and wherein the borehole is an
3 extended reach lateral wellbore.
4

5 In accordance with the above, another preferred
6 embodiment of the invention is a method of drilling a
7 borehole from an offshore platform with a coiled tubing
8 conveyed mud motor driven rotary drill bit having at least
9 one mud passage for passing mud into the borehole from within
10 the tubing comprising at least the steps of: (a) attaching
11 the mud motor driven rotary drill bit to the coiled tubing;
12 (b) drilling the well from the offshore platform with the
13 tubing conveyed mud motor driven rotary drill bit to a
14 desired depth; and (c) completing the well with the mud motor
15 driven rotary drill bit attached to the drill string to make
16 a steel cased well. Such a method applies wherein the
17 borehole is an extended reach wellbore and wherein the
18 borehole is an extended reach lateral wellbore.
19

20 In accordance with the above, another preferred
21 embodiment of the invention is a method of one pass drilling
22 from an offshore platform of a geological formation of
23 interest to produce hydrocarbons comprising at least the
24 following steps: (a) attaching a drill bit to a casing
25 string located on an offshore platform; (b) drilling a
26 borehole into the earth from the offshore platform to a
27 geological formation of interest; (c) providing a pathway for
28 fluids to enter into the casing from the geological formation
29 of interest; (d) completing the well adjacent to the
30 formation of interest with at least one of cement, gravel,
31 chemical ingredients, mud; and (e) passing the hydrocarbons
32 through the casing to the surface of the earth while the
33 drill bit remains attached to the casing. Such a method
34 applies wherein the borehole is an extended reach wellbore.

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1 and wherein the borehole is an extended reach lateral
2 wellbore.

3
4 In accordance with the above, another preferred
5 embodiment of the invention is a method of drilling a
6 borehole into a geological formation from an offshore
7 platform using casing as at least a portion of the drill
8 string and completing the well with the casing during one
9 single drilling pass into the geological formation.

10
11 In accordance with the above, yet another preferred
12 embodiment of the invention is a method of drilling a well
13 from an offshore platform possessing a riser and a blowout
14 preventer with a drill string, at least a portion of the
15 drill string comprising casing, comprising at least the step
16 of penetrating the riser and the blowout preventer with the
17 drill string.

18
19 In accordance with the above, yet another preferred
20 embodiment of the invention is a method of drilling a well
21 from an offshore platform possessing a riser with a drill
22 string, at least a portion of the drill string comprising
23 casing, comprising at least the step of penetrating the riser
24 with the drill string.

25
26 Please note that several steps in the One-Trip-Down-
27 Drilling process had already been finished in Figure 5.
28 However, it is instructive to take a look at one preferred
29 method of well completion that leads to the configuration in
30 Figure 5. Figure 6 shows one of the earlier steps in that
31 preferred embodiment of well completion that leads to the
32 configuration shown in Figure 5. Further, Figure 6 shows an
33 embodiment of the invention that may be used with MWD/LWD
34 measurements as described below.

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Retrievable Instrumentation Packages

Figure 6 shows an embodiment of the invention that is particularly configured so that Measurement-While-Drilling (MWD) and Logging-While-Drilling (LWD) can be done during the drilling operations, but that following drilling operations employing MWD/LWD measurements, Smart Shuttles may be used thereafter to complete oil and gas production from the offshore platform using procedures and apparatus described in the following. Numerals 150 through 184 had been previously described in relation to Figure 5. In addition in Figure 6, the last section of standard drill pipe, or casing as appropriate, 186 is connected by threaded means to Smart Drilling and Completion Sub 188, that in turn is connected by threaded means to Bit Adaptor Sub 190, that is in turn connected by threaded means to rotary drill bit 192. As an option, this drill bit may be chosen by the operator to be a "Smart Bit" as described in the following.

The Smart Drilling and Completion Sub has provisions for many features. Many of these features are optional, so that some or all of them may be used during the drilling and completion of any one well. Many of those features are described in detail in U.S. Disclosure Document No. 452648 filed on March 5, 1999 that has been previously recited above. In particular, that U.S. Disclosure Document discloses the utility of "Retrievable Instrumentation Packages" that is described in detail in Figures 7 and 7A therein. Specifically, the preferred embodiment herein provides Smart Drilling and Completion Sub 188 that in turn surrounds the Retrievable Instrumentation Package 194 as shown in Figure 6.

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1 As described in U.S. Disclosure Document No. 452648,
2 to maximize the drilling distance of extended reach lateral
3 drilling, a preferred embodiment of the invention possess the
4 option to have means to perform measurements with sensors to
5 sense drilling parameters, such as vibration, temperature,
6 and lubrication flow in the drill bit - to name just a few.
7 The sensors may be put in the drill bit 192, and if any such
8 sensors are present, the bit is called a "Smart Bit" for the
9 purposes herein. Suitable sensors to measure particular
10 drilling parameters, particularly vibration, may also be
11 placed in the Retrievable Instrumentation Package 194 in
12 Figure 6. So, the Retrievable Instrumentation Package 194
13 may have "drilling monitoring instrumentation" that is an
14 example of "drilling monitoring instrumentation means".
15

16 Any such measured information in Figure 6 can be
17 transmitted to the surface. This can be done directly from
18 the drill bit, or directly from any locations in the drill
19 string having suitable electronic receivers and transmitters
20 ("repeaters"). As a particular example, the measured
21 information may be relayed from the Smart Bit to the
22 Retrievable Instrumentation Package for final transmission
23 to the surface. Any measured information in the Retrievable
24 Instrumentation Package is also sent to the surface from its
25 transmitter. As set forth in the above U.S. Disclosure
26 Documents No. 452648, an actuator in the drill bit in certain
27 embodiments of the invention can be controlled from the
28 surface that is another optional feature of Smart Bit 192 in
29 Figure 6. If such an actuator is in the drill bit, and/or if
30 the drill bit has any type communication means, then the bit
31 is also called a Smart Bit for the purposes herein. As
32 various options, commands could be sent directly to the drill
33 bit from the surface or may be relayed from the Retrievable
34 Instrumentation Package to the drill bit. Therefore, the

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1 Retrievable Instrumentation Package may have "drill bit
2 control instrumentation" that is an example of a "drill bit
3 control instrumentation means" which is used to control such
4 actuators in the drill bit.

5
6 In one preferred embodiment of the invention, commands
7 sent to any Smart Bit to change the configuration of the
8 drill bit to optimize drilling parameters in Figure 6 are
9 sent from the surface to the Retrievable Instrumentation
10 Package using a "first communication channel" which are in
11 turn relayed by repeater means to the rotary drill bit 192
12 that itself in this case is a "Smart Bit" using a "second
13 communications channel". Any other additional commands sent
14 from the surface to the Retrievable Instrumentation Package
15 could also be sent in that "first communications channel".
16 As another preferred embodiment of the invention, information
17 sent from any Smart Bit that provides measurements during
18 drilling to optimize drilling parameters can be sent from the
19 Smart Bit to the Retrievable Instrumentation Package using a
20 "third communications channel", which are in turn relayed to
21 the surface from the Retrievable Instrumentation Package
22 using a "fourth communication channel". Any other
23 information measured by the Retrievable Instrumentation
24 Package such as directional drilling information and/or
25 information from MWD/LWD measurements would also be added to
26 that fourth communications channel for simplicity. Ideally,
27 the first, second, third, and fourth communications channels
28 can send information in real time simultaneously. Means to
29 send information includes acoustic modulation means,
30 electromagnetic means, etc., that includes any means
31 typically used in the industry suitably adapted to make the
32 first, second, third, and fourth communications channels.
33 In principle, any number of communications channels
34 "N" can be used, all of which can be designed to function

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1 simultaneously. The above is one description of a
2 "communications instrumentation". Therefore, the Retrievable
3 Instrumentation Package has "communications instrumentation"
4 that is an example of "communications instrumentation means".
5

6 In a preferred embodiment of the invention the
7 Retrievable Instrumentation package includes a "directional
8 assembly" meaning that it possesses means to determine
9 precisely the depth, orientation, and all typically required
10 information about the location of the drill bit and the drill
11 string during drilling operations. The "directional
12 assembly" may include accelerometers, magnetometers,
13 gravitational measurement devices, or any other means to
14 determine the depth, orientation, and all other information
15 that has been obtained during typical drilling operations.
16 In principle this directional package can be put in many
17 locations in the drill string, but in a preferred embodiment
18 of the invention, that information is provided by the
19 Retrievable Instrumentation Package. Therefore, the
20 Retrievable Instrumentation Package has a "directional
21 measurement instrumentation" that is an example of a
22 "directional measurement instrumentation means".
23

24 As another option, and as another preferred embodiment,
25 and means used to control the directional drilling of the
26 drill bit, or Smart Bit, in Figure 6 can also be similarly
27 incorporated in the Retrievable Instrumentation Package.
28 Any hydraulic contacts necessary with formation can be
29 suitably fabricated into the exterior wall of the Smart
30 Drilling and Completion Sub 188. Therefore, the Retrievable
31 Instrumentation Package may have "directional drilling
32 control apparatus and instrumentation" that is an example of
33 "directional drilling control apparatus and instrumentation
34 means".

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1 As an option, and as a preferred embodiment of the
2 invention, the characteristics of the geological formation
3 can be measured using the device in Figure 6. In principle,
4 MWD ("Measurement-While-Drilling") or LWD ("Logging-While-
5 Drilling") packages can be put in the drill string at many
6 locations. In a preferred embodiment shown in Figure 6, the
7 MWD and LWD electronics are made a part of the Retrievable
8 Instrumentation Package inside the Smart Drilling and
9 Completion Sub 188. Not shown in Figure 6, any sensors that
10 require external contact with the formation such as
11 electrodes to conduct electrical current into the formation,
12 acoustic modulator windows to let sound out of the assembly,
13 and other special windows suitable for passing natural gamma
14 rays, gamma rays from spectral density tools, neutrons, etc.,
15 which are suitably incorporated into the exterior walls of
16 the Smart Drilling and Completion Sub. Therefore, the
17 Retrievable Instrumentation Package may have "MWD/LWD
18 instrumentation" that is an example of "MWD/LWD
19 instrumentation means".

20
21 Yet further, the Retrievable Instrumentation Package may
22 also have active vibrational control devices. In this case,
23 the "drilling monitoring instrumentation" is used to control
24 a feedback loop that provides a command via the
25 "communications instrumentation" to an actuator in the
26 Smart Bit that adjusts or changes bit parameters to optimize
27 drilling, and avoid "chattering", etc. See the article
28 entitled "Directional drilling performance improvement",
29 by M. Mims, World Oil, May 1999, pages 40-43, an entire copy
30 of which is incorporated herein. Therefore, the Retrievable
31 Instrumentation Package may also have "active feedback
32 control instrumentation and apparatus to optimize drilling
33 parameters" that is an example of "active feedback and
34

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1 control instrumentation and apparatus means to optimize
2 drilling parameters".

3
4 Therefore, the Retrieval Instrumentation Package in the
5 Smart Drilling and Completion Sub in Figure 6 may have one or
6 more of the following elements:

7
8 (a) mechanical means to pass mud through the body of
9 188 to the drill bit;

10
11 (b) retrieving means, including latching means, to
12 accept and align the Retrievable Instrumentation Package
13 within the Smart Drilling and Completion Sub;

14
15 (c) "drilling monitoring instrumentation" or "drilling
16 monitoring instrumentation means";

17
18 (d) "drill bit control instrumentation" or "drill bit
19 control instrumentation means";

20
21 (e) "communications instrumentation" or "communications
22 instrumentation means";

23
24 (f) "directional measurement instrumentation" or
25 "directional measurement instrumentation means";

26
27 (g) "directional drilling control apparatus and
28 instrumentation" or "directional drilling control
29 apparatus and instrumentation means";

30
31 (h) "MWD/LWD instrumentation" or "MWD/LWD
32 instrumentation means" which provide typical geophysical
33 measurements which include induction measurements,
34 laterolog measurements, resistivity measurements,

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1 dielectric measurements, magnetic resonance imaging
2 measurements, neutron measurements, gamma ray
3 measurements; acoustic measurements, etc.

4
5 (i) "active feedback and control instrumentation and
6 apparatus to optimize drilling parameters" or "active
7 feedback and control instrumentation and apparatus means
8 to optimize drilling parameters";

9
10 (j) an on-board power source in the Retrievable
11 Instrumentation Package or "on-board power source means
12 in the Retrievable Instrumentation Package";

13
14 (k) an on-board mud-generator as is used in the industry
15 to provide energy to (j) above or "mud-generator means".

16
17 (l) batteries as are used in the industry to provide
18 energy to (j) above or "battery means";

19
20 For the purposes of this invention, any apparatus having
21 one or more of the above features (a), (b),, (j),
22 (k), or (l), AND which can also be removed from the Smart
23 Drilling and Completion Sub as described below in relation
24 to Figure 7, shall be defined herein as a Retrievable
25 Instrumentation Package, that is an example of a retrievable
26 instrument package means.

27
28 **Figure 7** shows a preferred embodiment of the invention
29 that is explicitly configured so that following drilling
30 operations that employ MWD/LWD measurements of formation
31 properties during those drilling operations, Smart Shuttles
32 may be used thereafter to complete oil and gas production
33 from the offshore platform. As in Figure 6, Smart Drilling
34 and Completion Sub 188 has disposed inside it Retrievable

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1 Instrumentation Package 194. The Smart Drilling and
2 Completion Sub has mud passage 196 through it. The
3 Retrievable Instrumentation Package has mud passage 198
4 through it. The Smart Drilling and Completion Sub has upper
5 threads 200 that engage the last section of standard drill
6 pipe, or casing as appropriate, 186 in Figure 6. The Smart
7 Drilling and Completion Sub has lower threads 202 that engage
8 the upper threads of the Bit Adaptor Sub 190 in Figure 6.

9
10 In Figure 7, the Retrievable Instrumentation Package has
11 high pressure walls 204 so that instrumentation in the
12 package is not damaged by pressure in the wellbore. It has
13 an inner payload radius r_1 , an outer payload radius r_2 , and
14 overall payload length L that are not shown for the purposes
15 of brevity. The Retrievable Instrumentation Package has
16 retrievable means 206 that allows a wireline conveyed device
17 from the surface to "lock on" and retrieve the Retrievable
18 Instrumentation Package. Element 206 is the "Retrieval Means
19 Attached to the Retrievable Instrumentation Package".

20
21 As shown in Figure 7, the Retrievable Instrumentation
22 Package may have latching means 208 that is disposed in latch
23 recession 210 that is actuated by latch actuator means 212.
24 The latching means 208 and latch recession 210 may function
25 as described above in previous embodiments or they may be
26 electronically controlled as required from inside the
27 Retrievable Instrumentation Package.

28
29 Guide recession 214 in the Smart Drilling and Completion
30 Sub is used to guide into place the Retrievable
31 Instrumentation Package having alignment spur 216. These
32 elements are used to guide the Retrievable Instrumentation
33 Package into place and for other purposes as described below.
34 These are examples of "alignment means".

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1 Acoustic transmitter/receiver 218 and current conducting
2 electrode 220 are used to measure various geological
3 parameters as is typical in the MWD/LWD art in the industry,
4 and they are "potted" in insulating rubber-like compounds 222
5 in the wall recession 224 shown in Figure 7. Various MWD/LWD
6 measurements are provided by MWD/LWD instrumentation (by
7 element 294 that is defined below) including induction
8 measurements, laterolog measurements, resistivity
9 measurements, dielectric measurements, magnetic resonance
10 imaging measurements, neutron measurements, gamma ray
11 measurements; acoustic measurements, etc. Power and signals
12 for acoustic transmitter/receiver 218 and current conducting
13 electrode 220 are sent over insulated wire bundles 226 and
14 228 to mating electrical connectors 232 and 234. Electrical
15 connector 234 is a high pressure connector that provides
16 power to the MWD/LWD sensors and brings their signals into
17 the pressure free chamber within the Retrievable
18 Instrumentation Package as are typically used in the
19 industry. Geometric plane "A" "B" is defined by those
20 legends appearing in Figure 7 for reasons which will be
21 explained later.

22
23 A first directional drilling control apparatus and
24 instrumentation is shown in Figure 7. Cylindrical drilling
25 guide 236 is attached by flexible spring coupling device 238
26 to moving bearing 240 having fixed bearing race 242 that is
27 anchored to the housing of the Smart Drilling and Completion
28 Sub near the location specified by the numeral 244. Sliding
29 block 246 has bearing 248 that makes contact with the inner
30 portion of the cylindrical drilling guide at the location
31 specified by numeral 250 that in turn sets the angle θ . The
32 cylindrical drilling guide 236 is free to spin when it is in
33 physical contact with the geological formation. So, during
34 rotary drilling, the cylindrical drilling guide spins about

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1 the axis of the Smart Drilling and Completion Sub that in
2 turn rotates with the remainder of the drill string. The
3 angle θ sets the direction in the x-y plane of the drawing in
4 Figure 7. Sliding block 246 is spring loaded with spring 252
5 in one direction (to the left in Figure 7) and is acted upon
6 by piston 254 in the opposite direction (to the right as
7 shown in Figure 7). Piston 254 makes contact with the
8 sliding block at the position designated by numeral 256 in
9 Figure 7. Piston 254 passes through bore 258 in the body of
10 the Smart Drilling and Completion Sub and enters the
11 Retrievable Instrumentation Package through o-ring 260.
12 Hydraulic piston actuator assembly 262 actuates the hydraulic
13 piston 254 under electronic control from instrumentation
14 within the Retrievable Instrumentation Package as described
15 below. The position of the cylindrical drilling guide 236
16 and its angle θ is held stable in the two dimensional plane
17 specified in Figure 7 by two competing forces described as
18 (a) and (b) in the following: (a) the contact between the
19 inner portion of the cylindrical drilling guide 236 and the
20 bearing 248 at the location specified by numeral 250; and
21 (b) the net "return force" generated by the flexible
22 spring coupling device 238. The return force generated
23 by the flexible spring coupling device is zero only when the
24 cylindrical drilling guide 236 is parallel to the body of
25 the Smart Drilling and Completion Sub.

26
27 There is a second such directional drilling control
28 apparatus located rotationally 90 degrees from the first
29 apparatus shown in Figure 7 so that the drill bit can be
30 properly guided in all directions for directional drilling
31 purposes. However, this second assembly is not shown in
32 Figure 7 for the purposes of brevity. This second assembly
33 sets the angle β in analogy to the angle θ defined above.
34 The directional drilling apparatus in Figure 7 is one example

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1 of "directional drilling control means". Directional
2 drilling in the oil and gas industries is also frequently
3 called "geosteering", particularly when geophysical
4 information is used in some way to direct the direction of
5 drilling, and therefore the apparatus in Figure 7 is also
6 an example of a "geosteering means".
7

8 The elements described in the previous two paragraphs
9 concerning Figure 7 provide an example of a directional
10 drilling means. In this case, it is not necessary to
11 periodically halt the rotary drilling so as to introduce into
12 the wellbore directional surveying means because data is
13 continuously sent uphole due to the existence of the
14 "communications instrumentation" and the "directional
15 measurement instrumentation" previously described above
16 (and in the foregoing). Nor does this apparatus require a
17 jet deflection bit to perform directional drilling.
18

19 When the Retrievable Instrumentation Package 194 has
20 been removed from the Smart Drilling and Completion Sub 188,
21 methods previously described in relation to Figures 1, 1A,
22 1B, 1C, and 1D may be used to complete the well.
23 Accordingly, methods of operation have been described in
24 relation to Figure 7 that provide an embodiment of the method
25 of directional drilling a well from the surface of the earth
26 and cementing a drill string into place within a wellbore to
27 make a cased well during one pass into formation using an
28 apparatus comprising at least a hollow drill string attached
29 to a rotary drill bit possessing directional drilling means,
30 the bit having at least one mud passage to convey drilling
31 mud from the interior of the drill string to the wellbore, a
32 source of drilling mud, a source of cement, and at least one
33 latching float collar valve assembly means, using at least
34 the following steps: (a) pumping the latching float collar

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1 valve means from the surface of the earth through the hollow
2 drill string with drilling mud so as to seat the latching
3 float collar valve means above the drill bit; and (b) pumping
4 cement through the seated latching float collar valve means
5 to cement the drill string and rotary drill bit into place
6 within the wellbore.

7
8 In relation to Figure 7, methods have been described for
9 an embodiment for selectively causing a drilling trajectory
10 to change during the drilling. In relation to Figure 6,
11 element 170 provides an embodiment of the means for lining
12 the wellbore with the casing portion. In the case of Figure
13 7, lower threads 202 engage the upper threads of Bit Adaptor
14 Sub 190 in Figure 6 so that the rotary drill bit 192 in
15 Figure 6 (an example of an earth removal member) is attached
16 to Smart Drilling and Completion Sub 188. In Figure 6, the
17 Smart Drilling and Completion Sub 188 is attached to standard
18 drill pipe, or casing as appropriate, 186 by upper threads
19 200 in Figure 7. Therefore, the drill string has an earth
20 removal member operatively connected thereto. Accordingly,
21 Figures 1, 1A, 1B, 1C, 1D, 6 and 7, and their related
22 description, have provided a method for drilling and lining
23 a wellbore comprising drilling the wellbore using a drill
24 string, the drill string having an earth removal member
25 operatively connected thereto and a casing portion for lining
26 the wellbore; selectively causing a drilling trajectory to
27 change during the drilling; and lining the wellbore with the
28 casing portion.

29
30 There are many other types of directional drilling
31 means. For a general review of the status of developments
32 on directional drilling control systems in the industry, and
33 their related uses, particularly in offshore environments,
34 please refer to the following references: (a) the article

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1 entitled "ROTARY-STEERABLE TECHNOLOGY - Part 1, Technology
2 gains momentum", by T. Warren, Oil and Gas Journal,
3 12/21/1998, pages 101-105, an entire copy of which is
4 incorporated herein by reference; (b) the article entitled
5 "ROTARY-STEERABLE TECHNOLOGY - Conclusion, Implementation
6 issues concern operators", by T. Warren, Oil and Gas Journal,
7 12/28/1998, pages 80-83, an entire copy of which is
8 incorporated herein by reference; (c) the entire issue of
9 World Oil dated December 1998 entitled in part on the front
10 cover "Marine Drilling Rigs, What's Ahead in 1999", an entire
11 copy of which is incorporated herein by reference; (d) the
12 entire issue of World Oil dated July 1999 entitled in part
13 on the front cover "Offshore Report" and "New Drilling
14 Technology", an entire copy of which is incorporated herein
15 in by reference; and (e) the entire issue of The American Oil
16 and Gas Reporter dated June 1999 entitled in part on the
17 front cover "Offshore & Subsea Technology", an entire copy
18 of which is incorporated herein by reference; (f) U.S.
19 Patent No. 5,332,048, having the inventors of Underwood
20 et. al., that issued on July 26, 1994 entitled in part
21 "Method and Apparatus for Automatic Closed Loop Drilling
22 System", an entire copy of which is incorporated herein by
23 reference; (g) and U.S. Patent No. 5,842,149 having the
24 inventors of Harrell et. al., that issued on November 24,
25 1998, that is entitled "Closed Loop Drilling System", an
26 entire copy of which is incorporated herein by reference.
27 Furthermore, all references cited in the above defined
28 documents (a) and (b) and (c) and (d) and (e) and (f)
29 and (g) in this paragraph are also incorporated herein in
30 their entirety by reference. Specifically, all 17 references
31 cited on page 105 of the article defined in (a) and all
32 3 references cited on page 83 of the article defined in
33 (b) are incorporated herein by reference. For further
34 reference, rotary steerable apparatus and rotary steerable

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1 systems may also be called "rotary steerable means", a term
2 defined herein. Further, all the terms that are used, or
3 defined in the above listed references (a), (b), (c), (d),
4 and (e) are incorporated herein in their entirety.

5
6 Figure 7 also shows a mud-motor electrical generator.
7 The mud-motor generator is only shown FIGURATIVELY in
8 Figure 7. This mud-motor electrical generator is
9 incorporated within the Retrievable Instrumentation Package
10 so that the mud-motor electrical generator is substantially
11 removed when the Retrievable Instrumentation Package is
12 removed from the Smart Drilling and Completion Sub. Such a
13 design can be implemented using a split-generator design,
14 where a permanent magnet is turned by mud flow, and pick-up
15 coils inside the Retrievable Instrumentation Package are used
16 to sense the changing magnetic field resulting in a voltage
17 and current being generated. Such a design does not
18 necessary need high pressure seals for turning shafts of the
19 mud-motor electrical generator itself. To figuratively show
20 a preferred embodiment of the mud-motor electrical generator
21 in Figure 7, element 264 is a permanently magnetized turbine
22 blade having magnetic polarity N and S as shown. Element 266
23 is another such permanently magnetized turbine blade having
24 similar magnetic polarity, but the N and S are not marked on
25 element 266 in Figure 7. These two turbine blades spin about
26 a bearing at the position designated by numeral 268 where the
27 two turbine blades cross in Figure 7. The details for the
28 support of that shaft are not shown in Figure 7 for the
29 purposes of brevity. The mud flowing through the mud passage
30 198 of the Retrievable Instrumentation Package causes the
31 magnetized turbine blades to spin about the bearing at
32 position 268. A pick-up coil mounted on magnetic bar
33 material designated by numeral 270 senses the changing
34 magnetic field caused by the spinning magnetized turbine

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1 blades and produces electrical output 272 that in turn
2 provides time varying voltage $V(t)$ and time varying current
3 $I(t)$ to yet other electronics described below that is used to
4 convert these waveforms into usable power as is required by
5 the Retrievable Instrumentation Package. The changing
6 magnetic field penetrates the high pressure walls 204 of the
7 Retrievable Instrumentation Package. For the figurative
8 embodiment of the mud-motor electrical generator shown in
9 Figure 7, non-magnetic steel walls are probably better to use
10 than walls made of magnetic materials. Therefore, the
11 Retrievable Instrumentation Package and the Smart Drilling
12 and Completion Sub may have a mud-motor electrical generator
13 for the purposes herein.

14
15 The following block diagram elements are also shown in
16 Figure 7: element 274, the electronic instrumentation to
17 sense, accept, and align (or release) the "Retrieval Means
18 Attached to the Retrievable Instrumentation Package" and to
19 control the latch actuator means 212 during acceptance
20 (or release); element 276, "power source" such as batteries
21 and/or electronics to accept power from mud-motor electrical
22 generator system and to generate and provide power as
23 required to the remaining electronics and instrumentation in
24 the Retrievable Instrumentation Package; element 278,
25 "downhole computer" controlling various instrumentation and
26 sensors that includes downhole computer apparatus that may
27 include processors, software, volatile memories, non-volatile
28 memories, data buses, analogue to digital converters as
29 required, input/output devices as required, controllers,
30 battery back-ups, etc.; element 280, "communications
31 instrumentation" as defined above; element 282, "directional
32 measurement instrumentation" as defined above; element 284,
33 "drilling monitoring instrumentation" as defined above;
34 element 286, "directional drilling control apparatus and

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1 instrumentation" as defined above; element 288, "active
2 feedback and control instrumentation to optimize drilling
3 parameters", as defined above; element 290, general purpose
4 electronics and logic to make the system function properly
5 including timing electronics, driver electronics, computer
6 interfacing, computer programs, processors, etc.; element
7 292, reserved for later use herein; and element 294 "MWD/LWD
8 instrumentation", as defined above.

9
10 In Figure 7, geophysical quantities are continuously
11 measured, and it is not necessary to introduce any separate
12 logging device into the wellbore to perform measurements.
13 Element 294 in Figure 7 is an embodiment of the "MWD/LWD
14 instrumentation" that is defined above. Item (h) above
15 defines "MWD/LWD instrumentation" or "MWD/LWD instrumentation
16 means" as devices which provide typical geophysical
17 measurements which include neutron measurements, gamma ray
18 measurements and acoustic measurements. Each of these
19 different devices may possess at least one geophysical
20 parameter sensing member to measure at least one geophysical
21 quantity. In a preferred embodiment of the invention
22 described herein, each such geophysical quantity is obtained
23 from measurements within a drill string or other metal
24 housing. In a preferred embodiment of the invention
25 described herein, the geophysical parameter sensing member
26 obtains its information from within the drill string or other
27 metal housing. In yet another embodiment of the invention,
28 no information is obtained from the open borehole. In
29 relation to Figures 6 and 7, the drill bit ("an earth removal
30 member") is connected to a drilling assembly (element 190 in
31 Figure 6 and element 188 in shown in Figures 6 and 7) that is
32 operatively connected to the drill pipe, or the casing
33 (elements 186 and 170 in Figure 6). Elements 192, 190, 188,
34 186, and 170 in Figure 6 provide an embodiment of a drill

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1 string having a casing portion for lining the wellbore. The
2 casing portion for lining the wellbore may comprise elements
3 186 and 170 in Figure 6. Accordingly, Figures 6 and 7 show
4 an embodiment of an apparatus for drilling a wellbore
5 comprising: a drill string having a casing portion for lining
6 the wellbore; a drilling assembly operatively connected to
7 the drill string and having an earth removal member and a
8 geophysical parameter sensing member.

9
10 Figure 7 also shows optional mud seal 296 on the
11 outer portion of the Retrievable Instrumentation Package
12 that prevents drilling mud from flowing around the outer
13 portion of that Package. Most of the drilling mud as
14 shown in Figure 7 flows through mud passages 196 and 198.
15 Mud seal 296 is shown figuratively only in Figure 7, and may
16 be a circular mud ring, but any type of mud sealing element
17 may be used, including the designs of elastomeric mud sealing
18 elements normally associated with wiper plugs as described
19 above and as used in the industry for a variety of purposes.

20
21 It should be evident that the functions attributed to
22 the single Smart Drilling and Completion Sub 188 and
23 Retrievable Instrumentation Package 194 may be arbitrarily
24 assigned to any number of different subs and different
25 pressure housings as is typical in the industry. However,
26 "breaking up" the Smart Drilling and Completion Sub and the
27 Retrievable Instrumentation Package are only minor variations
28 of the preferred embodiment described herein.

29
30 Perhaps it is also worth noting that a primary reason
31 for inventing the Retrievable Instrumentation Package 194 is
32 because in the event of One-Trip-Down-Drilling, then the
33 drill bit and the Smart Drilling and Completion Sub are left
34 in the wellbore to save the time and effort to bring out the

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1 drill pipe and replace it with casing. However, if the
2 MWD/LWD instrumentation is used as in Figure 7, the
3 electronics involved is often considered too expensive to
4 abandon in the wellbore. Further, major portions of the
5 directional drilling control apparatus and instrumentation
6 and the mud-motor electrical generator are also relatively
7 expensive, and those portions often need to be removed to
8 minimize costs. Therefore, the Retrievable Instrumentation
9 Package 194 is retrieved from the wellbore before the well is
10 thereafter completed to produce hydrocarbons.

11
12 The preferred embodiment of the invention in Figure 7
13 has one particular virtue that is of considerable value.
14 When the Retrievable Instrumentation Package 194 is pulled to
15 the left with the Retrieval Means Attached to the Retrievable
16 Instrumentation Package 206, then mating connectors 232 and
17 234 disengage, and piston 254 is withdrawn through the bore
18 258 in the body of the Smart Drilling and Completion Sub.
19 The piston 254 had made contact with the sliding block 246 at
20 the location specified by numeral 256, and when the
21 Retrievable Instrumentation Package 194 is withdrawn, the
22 piston 254 is free to be removed from the body of the Smart
23 Drilling and Completion Sub. The Retrievable Instrumentation
24 Package "splits" from the Smart Drilling and Completion Sub
25 approximately along plane "A" "B" defined in Figure 7. In
26 this way, most of the important and expensive electronics and
27 instrumentation can be removed after the desired depth is
28 reached. With suitable designs of the directional drilling
29 control apparatus and instrumentation, and with suitable
30 designs of the mud-motor electrical generator, the most
31 expensive portions of these components can be removed with
32 the Retrievable Instrumentation Package.

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1 The preferred embodiment in Figure 7 has yet another
2 important virtue. If there is any failure of the Retrievable
3 Instrumentation Package before the desired depth has been
4 reached, it can be replaced with another unit from the
5 surface without removing the pipe from the well using
6 methods to be described in the following. This feature would
7 save considerable time and money that is required to "trip
8 out" a standard drill string to replace the functional
9 features of the instrumentation now in the Retrievable
10 Instrumentation Package.

11
12 In any event, after the total depth is reached in
13 Figure 6, and if the Retrievable Instrumentation Package
14 had MWD and LWD measurement packages as described in
15 Figure 7, then it is evident that sufficient geological
16 information is available vs. depth to complete the well and
17 to commence hydrocarbon production. Then, the Retrievable
18 Instrumentation Package can be removed from the pipe using
19 techniques to be described in the following.

20
21 It should also be noted that in the event that the
22 wellbore had been drilled to the desired depth, but on the
23 other hand, the MWD and LWD information had NOT been obtained
24 from the Retrievable Instrumentation Package during that
25 drilling, and following its removal from the pipe, then
26 measurements of the required geological formation properties
27 can still be obtained from within the steel pipe using the
28 logging techniques described above under the topic of
29 "Several Recent Changes in the Industry" - and please refer
30 to item (b) under that category. Logging through steel pipes
31 and logging through casings to obtain the required
32 geophysical information are now possible.

33
34
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1 In any event, let us assume that at this point in the
2 One-Trip-Down-Drilling Process that the following is the
3 situation: (a) the wellbore has been drilled to final depth;
4 (b) the configuration is as shown in Figure 6 with the
5 Retrievable Instrumentation Package at depth; and (c)
6 complete geophysical information has been obtained with
7 the Retrievable Instrumentation Package.

8
9 As described earlier in relation to Figure 7, the
10 Retrievable Instrumentation Package has retrieval means 206
11 that allows a wireline conveyed device operated from the
12 surface to "lock on" and retrieve the Retrievable
13 Instrumentation Package. Element 206 is the "Retrieval
14 Means Attached to the Retrievable Instrumentation Package" in
15 Figure 7. As one form of the preferred embodiment shown in
16 Figure 7, element 206 may have retrieval groove 298 that will
17 assist the wireline conveyed device from the surface to "lock
18 on" and retrieve the Retrievable Instrumentation Package.

19
20 As previously discussed above in relation to Figures 6
21 and 7, the drill string may include elements 192, 190, 188,
22 186 and 170. Element 192 has been previously described as an
23 "earth removal member" that is attached to the Bit Adaptor
24 Sub 190. The Smart Drilling and Completion Sub 188 surrounds
25 the Retrievable Instrumentation Package 194. Element 194 as
26 previously described contains geophysical measurement
27 instrumentation or geophysical measurement means. Element
28 194 also contains directional drilling means comprised of
29 elements 254, 258, 260 and 262. In a preferred embodiment of
30 the invention, all the geophysical measurement
31 instrumentation within element 194 is eliminated and the
32 geophysical measurements are provided by separate logging
33 tools placed into the drill string. Element 194 with all
34 geophysical measurement instrumentation removed is defined as

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1 element 195 herein. Element 195 is not shown in Figure 7 for
2 the purposes of brevity. In a preferred embodiment, a
3 drilling assembly does not possess geophysical measurement
4 means. In one preferred embodiment, elements 188, 190, 192,
5 and 195 comprise a drilling assembly. Therefore, element 195
6 is an example of a portion of the drilling assembly being
7 selectively removable from the wellbore without removing the
8 casing portion.

9
10 Elements 188, 190, 192, and 195 comprise an embodiment
11 of a drilling assembly operatively connected to the drill
12 string. A casing section of that drill string in a preferred
13 embodiment includes elements 170 and 186. That casing
14 section may be used as a casing portion for lining the
15 wellbore. Therefore, Figures 6 and 7 show an embodiment of
16 an apparatus for drilling a wellbore comprising a drill
17 string having a casing portion for lining the wellbore.
18 Further, in relation to Figures 6 and 7, an embodiment of an
19 apparatus has been described that possesses a drilling
20 assembly operatively connected to the drill string and having
21 an earth removal member.

22
23 Element 195 is an example of a selectively removable
24 portion of the drilling assembly. As described above,
25 element 195 is selectively removable from the wellbore.
26 The removal of element 195 does not require the removal of
27 the casing portion 170 and 186. Accordingly, an embodiment
28 of an apparatus has been described that has a portion of the
29 drilling assembly being selectively removable from the
30 wellbore without removing the casing portion.

31
32 In view of the above, a preferred embodiment of the
33 invention is an apparatus for drilling a wellbore comprising:
34 a drill string having a casing portion for lining the

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1 wellbore; and a drilling assembly operatively connected to
2 the drill string and having an earth removal member; a
3 portion of the drilling assembly being selectively removable
4 from the wellbore without removing the casing portion.
5

6 In view of the above, Figures 6 and 7 also show an
7 embodiment of an apparatus for drilling a wellbore
8 comprising: a drill string having a casing portion for lining
9 the wellbore; and a drilling assembly selectively connected
10 to the drill string and having an earth removal member.
11

12 When element 195 has been removed from the Smart
13 Drilling and Completion Sub 188, methods previously described
14 in relation to Figures 1, 1A, 1B, 1C, and 1D may be used to
15 complete the well. The definition of a tubular has been
16 defined in relation to Figure 1. Elements 170 and 186 in
17 Figure 6 are examples of tubulars. Using previously
18 described completion methods, Figures 6 and 7 provide a
19 method for lining a wellbore with a tubular. As previously
20 discussed in relation to Figure 6, the drill string may
21 include elements 192, 190, 188, 186 and 170. A casing
22 section of that drill string in a preferred embodiment
23 includes elements 170 and 186. Therefore, in relation to
24 Figures 6 and 7, methods are presented for drilling the
25 wellbore using a drill string, the drill string having a
26 casing portion. Figure 6 shows an embodiment of locating the
27 casing portion (elements 170 and 186) within the wellbore.
28 The phrase "physically alterable bonding material" has been
29 defined in the specification related to Figure 1 and is used
30 as a substitute for cement in previously described methods.
31

32 A portion of the above specification states the
33 following: 'As the water pressure is reduced on the inside
34 of the drill pipe, then the cement in the annulus between the

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1 drill pipe and the hole can cure under ambient hydrostatic
2 conditions. This procedure herein provides an example of the
3 proper operation of a "one-way cement valve means".
4 Therefore, methods have been described in relation to
5 Figure 1 for establishing a hydrostatic pressure condition
6 in the wellbore and allowing the cement to cure under the
7 hydrostatic pressure conditions. In relation to the
8 definition of a physically alterable bonding material,
9 therefore, methods have been described in relation to
10 Figure 1 for establishing a hydrostatic pressure condition in
11 the wellbore, and allowing the bonding material to physically
12 alter under the hydrostatic pressure condition.
13

14 The above in relation to Figures 6 and 7 has therefore
15 described a method for lining a wellbore with a tubular
16 comprising: drilling the wellbore using a drill string, the
17 drill string having a casing portion; locating the casing
18 portion within the wellbore; placing a physically alterable
19 bonding material in an annulus formed between the casing
20 portion and the wellbore; establishing a hydrostatic pressure
21 condition in the wellbore; and allowing the bonding material
22 to physically alter under the hydrostatic pressure condition.
23

24 In accordance with the above in relation to Figures 6
25 and 7, methods have been described to allow physically
26 alterable bonding material to cure thereby encapsulating the
27 drill string in the wellbore with cured bonding material.
28 In accordance with the above, methods have been described for
29 encapsulating the drill string and rotary drill bit within
30 the borehole with cured bonding material during one pass into
31 formation. In accordance with the above, methods have been
32 described for pumping physically alterable bonding material
33 through a float collar valve means to encapsulate a drill
34

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1 string and rotary drill bit with cured bonding material
2 within the wellbore.

3 4 5 Smart Shuttles 6

7 Figure 8 shows an example of such a wireline conveyed
8 device operated from the surface of the earth used to
9 retrieve devices within the steel drill pipe that is
10 generally designated by numeral 300. A wireline 302,
11 typically having 7 electrical conductors with an armor
12 exterior, is attached to the cablehead, generally labeled
13 with numeral 304 in Figure 8. Cablehead 304 is in turn
14 attached to the Smart Shuttle that is generally shown
15 as numeral 306 in Figure 8, which in turn is connected
16 to an attachment. In this case, the attachment is the
17 "Retrieval & Installation Subassembly", otherwise abbreviated
18 as the "Retrieval/Installation Sub", also simply abbreviated
19 as the "Retrieval Sub", and it is generally shown as numeral
20 308 in Figure 8. The Smart Shuttle is used for a number of
21 different purposes, but in the case of Figure 8, and in the
22 sequence of events described in relation to Figures 6 and 7,
23 it is now appropriate to retrieve the Retrievable
24 Instrumentation Package installed in the drill string as
25 shown in Figures 6 and 7. To that end, please note that
26 electronically controllable retrieval snap ring assembly 310
27 is designed to snap into the retrieval grove 298 of element
28 206 when the mating nose 312 of the Retrieval Sub enters mud
29 passage 198 of the Retrievable Instrumentation Package.
30 Mating nose 312 of the Retrieval Sub also has retrieval sub
31 electrical connector 313 (not shown in Figure 8) that
32 provides electrical commands and electrical power received
33 from the wireline and from the Smart Shuttle as is
34 appropriate. (For the record, the retrieval sub electrical

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1 connector 313 is not shown explicitly in Figure 8 because
2 the scale of that drawing is too large, but electrical
3 connector 313 is explicitly shown in Figure 9 where the scale
4 is appropriate.)
5

6 Figure 8 shows a portion of an entire system to
7 automatically complete oil and gas wells. This system is
8 called the "Automated Smart Shuttle Oil and Gas Completion
9 System", or also abbreviated as the "Automated Smart Shuttle
10 System", or the "Smart Shuttle Oil and Gas Completion
11 System". In Figure 8, the floor of the offshore platform 314
12 is attached to riser 156 having riser hanger apparatus 315 as
13 is typically used in the industry. The drill pipe 170, or
14 casing as appropriate, is composed of many lengths of drill
15 pipe and a first blowout preventer 316 is suitably installed
16 on an upper section of the drill pipe using typical art in
17 the industry. This first blowout preventer 316 has automatic
18 shut off apparatus 318 and manual back-up apparatus 319 as is
19 typical in the industry. A top drill pipe flange 320 is
20 installed on the top of the drill string.
21

22 The "Wiper Plug Pump-Down Stack" is generally shown as
23 numeral 322 in Figure 8. The reason for the name for this
24 assembly will become clear in the following. Wiper Plug
25 Pump-Down Stack" 322 is comprised various elements including
26 the following: lower pump-down stack flange 324, cylindrical
27 steel pipe wall 326, upper pump-down stack flange 328, first
28 inlet tube 330 with first inlet tube valve 332, second inlet
29 tube 334 with second inlet tube valve 336, third inlet tube
30 338 with third inlet tube valve 340, with primary injector
31 tube 342 with primary injector tube valve 344. Particular
32 regions within the "Wiper Plug Pump-Down Stack" are
33 identified respectively with legends A, B and C that are
34 shown in Figure 8. Bolts and bolt patterns for the lower

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1 pump-down stack flange 324, and its mating part that is top
2 drill pipe flange 320, are not shown for simplicity. Bolts
3 and bolt patterns for the upper pump down stack flange 328,
4 and its respective mating part to be describe in the
5 following, are also not shown for simplicity. In general in
6 Figure 8, flanges may have bolts and bolt patterns, but those
7 are not necessarily shown for the purposes of simplicity.

8
9 The "Smart Shuttle Chamber" 346 is generally shown in
10 Figure 8. Smart Shuttle chamber door 348 is pressure sealed
11 with a one-piece O-ring identified with the numeral 350.
12 That O-ring is in a standard O-ring grove as is used in the
13 industry. Bolt hole 352 through the Smart Shuttle chamber
14 door mates with mounting bolt hole 354 on the mating flange
15 body 356 of the Smart Shuttle Chamber. Tightened bolts will
16 firmly hold the Smart Shuttle chamber door 348 against the
17 mating flange body 356 that will suitably compress the one-
18 piece O-ring 350 to cause the Smart Shuttle Chamber to seal
19 off any well pressure inside the Smart Shuttle Chamber.

20
21 Smart Shuttle Chamber 346 also has first Smart Shuttle
22 chamber inlet tube 358 and first Smart Shuttle chamber inlet
23 tube valve 360. Smart Shuttle Chamber 346 also has second
24 Smart Shuttle chamber inlet tube 362 and second Smart Shuttle
25 chamber inlet tube valve 364. Smart Shuttle Chamber 346 has
26 upper Smart Shuttle chamber cylindrical wall 366 and upper
27 smart Shuttle Chamber flange 368 as shown in Figure 8. The
28 Smart Shuttle Chamber 346 has two general regions identified
29 with the legends D and E in Figure 8. Region D is the
30 accessible region where accessories may be attached or
31 removed from the Smart Shuttle, and region E has a
32 cylindrical geometry below second Smart Shuttle chamber inlet
33 tube 362. The Smart Shuttle and its attachments can be
34 "pulled up" into region E from region D for various purposes

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1 to be described later. Smart Shuttle Chamber 346 is attached
2 by the lower Smart Shuttle flange 370 to upper pump-down
3 stack flange 328. The entire assembly from the lower Smart
4 Shuttle flange 370 to the upper Smart Shuttle chamber flange
5 368 is called the "Smart Shuttle Chamber System" that is
6 generally designated with the numeral 372 in Figure 8. The
7 Smart Shuttle Chamber System 372 includes the Smart Shuttle
8 Chamber itself that is numeral 346 which is also referred to
9 as region D in Figure 8.

10
11 The "Wireline Lubricator System" 374 is also generally
12 shown in Figure 8. Bottom flange of wireline lubricator
13 system 376 is designed to mate to upper Smart Shuttle chamber
14 flange 368. These two flanges join at the position marked by
15 numeral 377. In Figure 8, the legend Z shows the depth from
16 this position 377 to the top of the Smart Shuttle.
17 Measurement of this depth Z, and knowledge of the length L1
18 of the Smart Shuttle (not shown in Figure 8 for simplicity),
19 and the length L2 of the Retrieval Sub (not shown in Figure 8
20 for simplicity), and all other pertinent lengths L3, L4,...,
21 of any apparatus in the wellbore, allows the calculation of
22 the "depth to any particular element in the wellbore" using
23 standard art in the industry.

24
25 The Wireline Lubricator System in Figure 8 has various
26 additional features, including a second blowout preventer
27 378, lubricator top body 380, fluid control pipe 382 and its
28 fluid control valve 384, a hydraulic packing gland generally
29 designated by numeral 386 in Figure 8, having gland sealing
30 apparatus 388, grease packing pipe 390 and grease packing
31 valve 392. Typical art in the industry is used to fabricate
32 and operate the Wireline Lubricator System, and for
33 additional information on such systems, please refer to
34 Figure 9, page 11, of Lesson 4, entitled "Well Completion

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1 Methods", of series entitled "Lessons in Well Servicing and
2 Workover", published by the Petroleum Extension Service of
3 The University of Texas at Austin, Austin, Texas, 1971, that
4 is incorporated herein by reference in its entirety, which
5 series was previously referred to above as "Ref. 2". In
6 Figure 8, the upper portion of the wireline 394 proceeds to
7 sheaves as are used in the industry and to a wireline drum
8 under computer control as described in the following.
9 However, at this point, it is necessary to further describe
10 relevant attributes of the Smart Shuttle.

11
12 The Smart Shuttle shown as element 306 in Figure 8 is an
13 example of "a conveyance means".
14

15 Figure 9 shows an enlarged view of the Smart Shuttle 306
16 and the "Retrieval Sub" 308 that are attached to the
17 cablehead 304 suspended by wireline 302. The cablehead has
18 shear pins 396 as are typical in the industry. A threaded
19 quick change collar 398 causes the mating surfaces of the
20 cablehead and the Smart Shuttle to join together at the
21 location specified by numeral 400. Typically 7 insulated
22 electrical conductors are passed through the location
23 specified by numeral 400 by suitable connectors and O-rings
24 as are used in the industry. Several of these wires will
25 supply the needed electrical energy to run the electrically
26 operated pump in the Smart Shuttle and other devices as
27 described below.
28

29 In Figure 9, a particular embodiment of the Smart
30 Shuttle is described which, in this case, has an
31 electrically operated internal pump, and this pump
32 is called the "internal pump of the Smart Shuttle" that
33 is designated by numeral 402. Numeral 402 designates an
34 "internal pump means". The upper inlet port 404 for the

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1 pump has electronically controlled upper port valve 406.
2 The lower inlet port 408 for the pump has electronically
3 controlled lower port valve 410. Also shown in Figure 9
4 is the bypass tube 412 having upper bypass tube valve 414 and
5 lower bypass tube valve 416. In a preferred embodiment of
6 the invention, the electrically operated internal pump 402 is
7 a "positive displacement pump". For such a pump, and if
8 valves 406 and 410 are open, then during any one specified
9 time interval Δt , a specific volume of fluid ΔV_1 is pumped
10 from below the Smart Shuttle to above the Smart Shuttle
11 through inlets 404 and 408 as they are shown in Figure 9.
12 For further reference, the "down side" of the Smart Shuttle
13 in Figure 9 is the "first side" of the Smart Shuttle and the
14 "up side" of the Smart Shuttle in Figure 9 is the "second
15 side" of the Smart Shuttle. Such up and down designations
16 loose their meaning when the wellbore is substantially a
17 horizontal wellbore where the Smart Shuttle will have great
18 utility. Please refer to the legends ΔV_1 on Figure 9. This
19 volume ΔV_1 relates to the movement of the Smart Shuttle as
20 described later below.

21
22 In Figure 9, the Smart Shuttle also has elastomer
23 sealing elements. The elastomer sealing elements on the
24 right-hand side of Figure 9 are labeled as elements 418 and
25 420. These elements are shown in a flexed state which are
26 mechanically loaded against the right-hand interior
27 cylindrical wall 422 of the Smart Shuttle Chamber 346 by the
28 hanging weight of the Smart Shuttle and related components.
29 The elastomer sealing elements on the left-hand side of
30 Figure 9 are labeled as elements 424 and 426, and are shown
31 in a relaxed state (horizontal) because they are not in
32 contact with any portion of a cylindrical wall of the Smart
33 Shuttle Chamber. These elastomer sealing elements are
34 examples of "lateral sealing means" of the Smart Shuttle.

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1 In the preferred embodiment shown in Figure 9, it is
2 contemplated that the right-hand element 418 and the
3 left-hand element 424 are portions of one single elastomeric
4 seal. It is further contemplated that the right-hand element
5 420 and the left-hand element 426 are portions of yet another
6 separate elastomeric seal. Many different seals are
7 possible, and these are examples of "sealing means"
8 associated with the Smart Shuttle.
9

10 Figure 9 further shows quick change collar 428 that
11 causes the mating surfaces of the lower portion of the Smart
12 Shuttle to join together to the upper mating surfaces of the
13 Retrieval Sub at the location specified by numeral 430.
14 Typically, 7 insulated electrical conductors are also passed
15 through the location specified by numeral 430 by suitable
16 mating electrical connectors as are typically used in
17 the industry. Therefore, power, control signals, and
18 measurements can be relayed from the Smart Shuttle to the
19 Retrieval Sub and from the Retrieval Sub to the Smart Shuttle
20 by suitable mating electrical connectors at the location
21 specified by numeral 430. To be thorough, it is probably
22 worthwhile to note here that numeral 431 is reserved to
23 figuratively designate the top electrical connector of
24 the Retrieval Sub, although that connector 431 is not shown
25 in Figure 9 for the purposes of simplicity. The position of
26 the electronically controllable retrieval snap ring assembly
27 310 is controlled by signals from the Smart Shuttle. With no
28 signal, the snap ring of assembly 310 is spring-loaded into
29 the position shown in Figure 9. With a "release command"
30 issued from the surface, electronically controllable
31 retrieval snap ring assembly 310 is retracted so that it does
32 NOT protrude outside vertical surface 432 (i.e., snap ring
33 assembly 310 is in its full retracted position). Therefore,
34 electronic signals from the surface are used to control the

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1 electronically controllable retrieval snap ring assembly 310,
2 and it may be commanded from the surface to "release"
3 whatever it had been holding in place. In particular,
4 once suitably aligned, assembly 310 may be commanded to
5 "engage" or "lock-on" retrieval grove 298 in the Retrievable
6 Instrumentation Package 206, or it can be commanded to
7 "release" or "pull back from" the retrieval grove 298 in the
8 Retrievable Instrumentation Package as may be required during
9 deployment or retrieval of that Package, as the case may be.

10
11 One method of operating the Smart Shuttle is as follows.
12 With reference to Figure 8, and if the first Smart Shuttle
13 chamber inlet tube valve 360 is in its open position, fluids,
14 such as water or drilling mud as required, are introduced
15 into the first Smart Shuttle chamber inlet tube 358. With
16 second Smart Shuttle chamber inlet tube valve 364 in its open
17 position, then the injected fluids are allowed to escape
18 through second Smart Shuttle chamber inlet tube 362 until
19 substantially all the air in the system has been removed.
20 In a preferred embodiment, the internal pump of the Smart
21 Shuttle 402 is a self-priming pump, so that even if any air
22 remains, the pump will still pump fluid from below the Smart
23 Shuttle, to above the Smart Shuttle. Similarly, inlets 330,
24 334, 338, and 342, with their associated valves, can also be
25 used to "bleed the system" to get rid of trapped air using
26 typical procedures often associated with hydraulic systems.
27 With reference to Figure 9, it would further help the
28 situation if valves 406, 410, 414 and 416 in the Smart
29 Shuttle were all open simultaneously during "bleeding
30 operations", although this may not be necessary. The point
31 is that using typical techniques in the industry, the entire
32 volume within the regions A, B, C, D, and E within the
33 interior of the apparatus in Figure 8 can be fluid filled
34 with fluids such as drilling mud, water, etc. This state of

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1 affairs is called the "priming" of the Automated Smart
2 Shuttle System in this preferred embodiment of the invention.

3
4 After the Automated Smart Shuttle System is primed, then
5 the wireline drum is operated to allow the Smart Shuttle and
6 the Retrieval Sub to be lowered from region D of Figure 8 to
7 the part of the system that includes regions A, B, and C.
8 Figure 10 shows the Smart Shuttle and Retrieval Sub in that
9 location.

10
11 The Smart Shuttle shown as element 306 in Figure 9 is an
12 example of "a conveyance means".

13
14 In Figure 10, all the numerals and legends in Figure 10
15 have been previously defined. When the Smart Shuttle and the
16 Retrieval Sub are located in regions A, B, and C, then the
17 elastomer sealing elements 418, 420, 424, and 426 positively
18 seal against the cylindrical walls of the now fluid filled
19 enclosure. Please notice the change in shape of the
20 elastomer sealing elements 424 and 426 in Figure 9 and in
21 Figure 10. The reason for this change is because the regions
22 A, B, and C are bounded by cylindrical metal surfaces with
23 intervening pipes such as inlet tubes 330, 334, 338, and
24 primary injector tube 342. In a preferred embodiment of the
25 invention, the vertical distance between elastomeric units
26 418 and 420 are chosen so that they do simultaneously overlap
27 any two inlet pipes to avoid loss a positive seal along the
28 vertical extent of the Smart Shuttle.

29
30 Then, in Figure 10, valves 414 and 416 are closed, and
31 valves 406 and 410 are opened. Thereafter, the electrically
32 operated internal pump 402 is turned "on". In a preferred
33 embodiment of the invention, the electrically operated
34 internal pump is a "positive displacement pump". For such a

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1 pump, and as had been previously described, during any one
2 specified time interval Δt , a specific volume of fluid ΔV_1
3 is pumped from below the Smart Shuttle to above the Smart
4 Shuttle through valves 406 and 410. Please refer to the
5 legends ΔV_1 on Figure 10. In Figure 10, The top of the
6 Smart Shuttle is at depth Z, and that legend was defined in
7 Figure 8 in relation to position 377 in that figure. In
8 Figure 10, the inside radius of the cylindrical portion of
9 the wellbore is defined by the legend a1. However, first it
10 is perhaps useful to describe several different embodiments
11 of Smart Shuttles and associated Retrieval Subs.
12

13 Element 306 in Figure 8 is the "Smart Shuttle". This
14 apparatus is "smart" because the "Smart Shuttle" has one or
15 more of the following features (hereinafter, "List of Smart
16 Shuttle Features"):
17

18 (a) it can provide depth measurement information, ie.,
19 it can have "depth measurement means"
20

21 (b) it can provide orientation information within the
22 metallic pipe, drill string, or casing, whatever is
23 appropriate, including the angle with respect to
24 vertical, and any azimuthal angle in the pipe as
25 required, and any other orientational information
26 required, ie., it can have "orientational information
27 measurement means"
28

29 (c) it can possess at least one power source, such as a
30 battery or batteries, or apparatus to convert electrical
31 energy from the wireline to power any sensors,
32 electronics, computers, or actuators as required, ie.,
33 it can have "power source means"
34

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1 (d) it can possess at least one sensor and associated
2 electronics including any required analogue to digital
3 converter devices to monitor pressure, and/or
4 temperature, such as vibrational spectra,
5 shock sensors, etc., ie., it can have "sensor
6 measurement means"

7
8 (e) it can receive commands sent from the surface, ie.,
9 it can have "command receiver means from surface"

10
11 (f) it can send information to the surface, ie., it
12 can have "information transmission means to surface"

13
14 (g) it can relay information to one or more portions of
15 the drill string, ie., it can have "tool relay
16 transmission means"

17
18 (h) it can receive information from one or more portions
19 of the drill string, ie., it can have "tool receiver
20 means"

21
22 (i) it can have one or more means to process
23 information, ie., it can have at least one
24 "processor means"

25
26 (j) it can have one or more computers to process
27 information, and/or interpret commands, and/or send
28 data, ie., it can have one or more "computer means"

29
30 (k) it can have one or more means for data storage

31
32 (l) it can have one or more means for nonvolatile
33 data storage if power is interrupted, ie., it can have
34 one or more "nonvolatile data storage means"

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1 (m) it can have one or more recording devices,
2 ie., it can have one or more "recording means"

3
4 (n) it can have one or more read only memories,
5 ie., it can have one or more "read only memory means"

6
7 (o) it can have one or more electronic controllers
8 to process information, ie., it can have one or more
9 "electronic controller means"

10
11 (p) it can have one or more actuator means to change
12 at least one physical element of the device in response
13 to measurements within the device, and/or commands
14 received from the surface, and/or relayed information
15 from any portion of the drill string

16
17 (q) the device can be deployed into a pipe of any type
18 including a metallic pipe, a drill string, a composite
19 pipe, a casing as is appropriate, by any means,
20 including means to pump it down with mud pressure by
21 analogy to a wiper plug, or it may use any type of
22 mechanical means including gears and wheels to engage
23 the casing, where such gears and wheels include any well
24 tractor type device, or it may have an electrically
25 operated pump and a seal, or it may be any type of
26 "conveyance means"

27
28 (r) the device can be deployed with any coiled tubing
29 device and may be retrieved with any coiled tubing
30 device, ie., it can be deployed and retrieved with any
31 "coiled tubing means"

32
33 (s) the device can be deployed with any coiled tubing
34 device having wireline inside the coiled tubing device

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1 (t) the device can have "standard depth control
2 sensors", which may also be called "standard geophysical
3 depth control sensors", including natural gamma ray
4 measurement devices, casing collar locators, etc., ie.,
5 the device can have "standard depth control measurement
6 means"

7
8 (u) the device can have any typical geophysical
9 measurement device described in the art including its
10 own MWD/LWD measurement devices described elsewhere
11 above, ie., it can have any "geophysical measurement
12 means"

13
14 (v) the device can have one or more electrically
15 operated pumps including positive displacement pumps,
16 turbine pumps, centrifugal pumps, impulse pumps, etc.,
17 ie., it can have one or more "internal pump means"

18
19 (w) the device can have a positive displacement pump
20 coupled to a transmission device for providing
21 relatively large pulling forces, ie., it can have one or
22 more "transmission means"

23
24 (x) the device can have two pumps in one unit, a
25 positive displacement pump to provide large forces and
26 relatively slow Smart Shuttle speeds and a turbine pump
27 to provide lesser forces at relatively high Smart
28 Shuttle speeds, ie., it may have "two or more internal
29 pump means"

30
31 (y) the device can have one or more pumps operated by
32 other energy sources
33
34

1 (z) the device can have one or more bypass assemblies
2 such as the bypass assembly comprised of elements 464,
3 466, 468, 470, and 472 in Figure 11, ie., it may have
4 one or more "bypass means"

5
6 (aa) the device can have one or more electrically
7 operated valves, ie., it can have one or more
8 electrically operated "valve means"

9
10 (ab) it can have attachments to it, or devices
11 incorporated in it, that install into the well and/or
12 retrieve from the well various "Well Completion Devices"
13 that are defined below
14

15 As mentioned earlier, a U.S. Trademark Application has
16 been filed for the Mark "Smart Shuttle". This Mark has
17 received a "Notice of Publication Under 12(a)" and it will be
18 published in the Official Gazette on June 11, 2002. Under
19 "LISTING OF GOODS AND/OR SERVICES" for the Mark "Smart
20 Shuttle" it states: "oil and gas industry hydraulically
21 driven or electrically driven conveyors to move equipment
22 through onshore and offshore wells, cased wells, open-hole
23 wells, pipes, tubings, expandable tubings, liners,
24 cylindrical sand screens, and production flowlines; the
25 conveyed equipment including well completion and production
26 devices, logging tools, perforating guns, well drilling
27 equipment, coiled tubings for well stimulation,
28 power cables, containers of chemicals, and flowline
29 cleaning equipment".
30

31 As mentioned earlier, a U.S. Trademark Application has
32 been filed for the Mark "Smart Shuttle". This Mark has
33 received a "Notice of Publication Under 12(a)" and it will be
34 published in the Official Gazette on June 11, 2002. The

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1 "LISTING OF GOODS AND/OR SERVICES" for Mark "Well Locomotive"
2 is the same as for "Smart Shuttle".
3

4 The "Retrieval & Installation Subassembly", otherwise
5 abbreviated as the "Retrieval/Installation Sub", also simply
6 abbreviated as the "Retrieval Sub", which is generally shown
7 as numeral 308, has one or more of the following features
8 (hereinafter, "List of Retrieval Sub Features"):
9

10 (a) it can be attached to, or is made a portion of, the
11 Smart Shuttle
12

13 (b) it can have means to retrieve apparatus disposed in
14 a pipe made of any material
15

16 (c) it can have means to install apparatus into a pipe
17 made of any material
18

19 (d) it can have means to install various completion
20 devices into a pipe made of any material
21

22 (e) it can have means to retrieve various completion
23 devices from a pipe made of any material
24

25 (f) it can have at least one sensor for measuring
26 information downhole, and apparatus for transmitting
27 that measured information to the Smart Shuttle or
28 uphole, apparatus for receiving commands if necessary,
29 and a battery or batteries or other suitable power
30 source as may be required
31

32 (g) it can be attached to, or be made a portion of,
33 a conveyance means such as a well tractor
34

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1 (h) it can be attached to, or be made a portion of, any
2 pump-down means of the types described later in this
3 document
4

5 Element 402 that is the "internal pump of the Smart
6 Shuttle" may be any electrically operated pump, or any
7 hydraulically operated pump that in turn, derives its power
8 in any way from the wireline. Standard art in the field is
9 used to fabricate the components of the Smart Shuttle and
10 that art includes all pump designs typically used in the
11 industry. Standard literature on pumps, fluid mechanics,
12 and hydraulics is also used to design and fabricate the
13 components of the Smart Shuttle, and specifically, the book
14 entitled "Theory and Problems of Fluid Mechanics and
15 Hydraulics", Third Edition, by R.V. Giles, J.B. Evett,
16 and C. Liu, Schaum's Outline Series, McGraw-Hill, Inc.,
17 New York, New York, 1994, 378 pages, is incorporated herein
18 in its entirety by reference.
19

20 For the purposes of several preferred embodiments of
21 this invention, an example of a "wireline conveyed smart
22 shuttle means having retrieval and installation means"
23 (also "wireline conveyed Smart Shuttle means having retrieval
24 and installation means") is comprised of the Smart Shuttle
25 and the Retrieval Sub shown in Figure 8. From the above
26 description, a Smart Shuttle may have many different features
27 that are defined in the above "List of Smart Shuttle
28 Features" and the Smart Shuttle by itself is called for the
29 purposes herein a "wireline conveyed smart shuttle means"
30 (also "wireline conveyed Smart Shuttle means), or simply a
31 "wireline conveyed shuttle means". A Retrieval Sub may have
32 many different features that are defined in the above "List
33 of Retrieval Sub Features" and for the purposes herein, it is
34 also described as a "retrieval and installation means".

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1 Accordingly, a particular preferred embodiment of a "wireline
2 conveyed shuttle means" has one or more features from the
3 "List of Smart Shuttle Features" and one or more features
4 from the "List of Retrieval Sub Features". Therefore, any
5 given "wireline conveyed shuttle means having retrieval and
6 installation means" may have a vast number of different
7 features as defined above. Depending upon the context, the
8 definition of a "wireline conveyed smart shuttle means having
9 retrieval and installation means" may include any first
10 number of features on the "List of Smart Shuttle Features"
11 and may include any second number of features on the "List of
12 Retrieval Sub Features". In this context, and for example,
13 a "wireline conveyed shuttle means having retrieval and
14 installation means" may have 4 particular features on the
15 "List of Smart Shuttle Features" and may have 3 features on
16 the "List of Retrieval Sub Features". The phrase "wireline
17 conveyed smart shuttle means having retrieval and
18 installation means" is also equivalently described for the
19 purposes herein as "wireline conveyed shuttle means
20 possessing retrieval and installation means".
21

22 It is now appropriate to discuss a generalized block
23 diagram of one type of Smart Shuttle. The block diagram of
24 another preferred embodiment of a Smart Shuttle is identified
25 as numeral 434 in Figure 11. Legends showing "UP" and "DOWN"
26 appear in Figure 11. Element 436 represents a block diagram
27 of a first electrically operated internal pump, and in this
28 preferred embodiment, it is a positive displacement pump,
29 which is associated with an upper port 438, electrically
30 controlled upper valve 440, upper tube 442, lower tube 444,
31 electrically controlled lower valve 446, and lower port 448,
32 which subsystem is collectively called herein "the Positive
33 Displacement Pump System". In Figure 11, there is another
34 second electrically operated internal pump, which in this

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1 case is an electrically operated turbine pump 450, which is
2 associated with an upper port 452, electrically operated
3 upper valve 454, upper tube 456, lower tube 458, electrically
4 operated lower valve 460, and lower port 462, which system
5 is collectively called herein "the Secondary Pump System".
6 Figure 11 also shows upper bypass tube 464, electrically
7 operated upper bypass valve 466, connector tube 468,
8 electrically operated lower bypass valve 470, and lower
9 bypass tube 472, which subsystem is collectively called
10 herein "the Bypass System". The 7 conductors (plus armor)
11 from the cablehead are connected to upper electrical plug 473
12 in the Smart Shuttle. The 7 conductors then proceed through
13 the upper portion of the Smart Shuttle that are figuratively
14 shown as numeral 474 and those electrically insulated wires
15 are connected to Smart Shuttle electronics system module 476.
16 The wire bundle pass through typically having 7 conductors
17 that provide signals and power from the wireline and the
18 Smart Shuttle to the Retrieval Sub are figuratively shown as
19 element 478 and these in turn are connected to lower
20 electrical connector 479. Signals and power from lower
21 electrical connector 479 within the Smart Shuttle are
22 provided as necessary to mating top electrical connector 431
23 of the Retrieval Sub and then those signals and power are in
24 turn passed through the Retrieval Sub to the retrieval sub
25 electrical connector 313 as shown in Figure 9. Smart Shuttle
26 electronics system module 476 carries out all the other
27 possible functions listed as items (a) to (z), and (aa) to
28 (ab), in the above defined list of "List of Smart Shuttle
29 Features", and those functions include all necessary
30 electronics, computers, processors, measurement devices, etc.
31 to carry out the functions of the Smart Shuttle. Various
32 outputs from the Smart Shuttle electronics system module 476
33 are figuratively shown as elements 480 to 498. As an
34 example, element 480 provides electrical energy to pump 436;

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1 element 482 provides electrical energy to pump 450; element
2 484 provides electrical energy to valve 440; element 486
3 provides electrical energy to valve 446; element 488 provides
4 electrical energy to valve 454; element 490 provides
5 electrical energy to valve 460; element 492 provides
6 electrical energy to valve 466; element 494 provides
7 electrical energy to valve 470; etc. In the end, there
8 may be a hundred or more additional electrical connections to
9 and from the Smart Shuttle electronics system module 476 that
10 are collectively represented by numerals 496 and 498. In
11 Figure 11, the right-hand and left-hand portions of upper
12 Smart Shuttle seal are labeled respectively 500 and 502.
13 Further, the right-hand and left-hand portions of lower Smart
14 Shuttle seal are labeled respectively with numerals 504 and
15 506. Not shown in Figure 11 are apparatus that may be used
16 to retract these seals under electronic control that would
17 protect the seals from wear during long trips into the hole
18 within mostly vertical well sections where the weight of the
19 smart shuttle means (also "Smart Shuttle means") is
20 sufficient to deploy it into the well under its own weight.
21 These seals would also be suitably retracted when the smart
22 shuttle means is pulled up by the wireline.

23
24 The preferred embodiment of the block diagram for a
25 Smart Shuttle has a particular virtue. Electrically operated
26 pump 450 is an electrically operated turbine pump, and when
27 it is operating with valves 454 and 460 open, and the rest
28 closed, it can drag significant loads downhole at relatively
29 high speeds. However, when the well goes horizontal, the
30 loads increase. If electrically operated pump 450 stalls or
31 cavitates, etc., then electrically operated pump 436 that is
32 a positive displacement pump takes over, and in this case,
33 valves 440 and 446 are open, with the rest closed. Pump 436
34 is a particular type of positive displacement pump that may

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1 be attached to a pump transmission device so that the load
2 presented to the positive displacement pump does not exceed
3 some maximum specification independent of the external load.
4 See Figure 12 for additional details.

5
6 The Smart Shuttle shown as element 306 in Figure 10 is
7 an example of "a conveyance means".
8

9 Figure 12 shows a block diagram of a pump transmission
10 device 508 that provides a mechanical drive 510 to positive
11 displacement pump 512. Electrical power from the wireline is
12 provided by wire bundle 514 to electric motor 516 and that
13 motor provides a mechanical coupling 518 to pump transmission
14 device 508. Pump transmission device 508 may be an
15 "automatic pump transmission device" in analogy to the
16 operation of an automatic transmission in a vehicle, or pump
17 transmission device 508 may be a "standard pump transmission
18 device" that has discrete mechanical gear ratios that are
19 under control from the surface of the earth. Such a pump
20 transmission device prevents pump stalling, and other pump
21 problems, by matching the load seen by the pump to the power
22 available by the motor. Otherwise, the remaining block
23 diagram for the system would resemble that shown in
24 Figure 11, but that is not shown here for the purposes
25 of brevity.
26

27 Another preferred embodiment of the Smart Shuttle
28 contemplates using a "hybrid pump/wheel device". In this
29 approach, a particular hydraulic pump in the Smart Shuttle
30 can be alternatively used to cause a traction wheel to engage
31 the interior of the pipe. In this hybrid approach, a
32 particular hydraulic pump in the Smart Shuttle is used in a
33 first manner as is described in Figures 8 - 12. In this
34 hybrid approach, and by using a set of electrically

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1 controlled valves, a particular hydraulic pump in the Smart
2 Shuttle is used in a second manner to cause a traction wheel
3 to rotate and to engage the pipe that in turn causes the
4 Smart Shuttle to translate within the pipe. There are many
5 designs possible using this "hybrid approach".
6

7 Figure 13 shows a block diagram of a preferred
8 embodiment of the Smart Shuttle having a hybrid pump design
9 that is generally designated with the numeral 520. Selected
10 elements ranging from element 436 to element 506 in Figure 13
11 have otherwise been defined in relation to Figure 11. In
12 addition, inlet port 522 is connected to electrically
13 controlled valve 524 that is in turn connected to two-state
14 valve 526 that may be commanded from the surface of the earth
15 to selectively switch between two states as follows:
16 "state 1" - the inlet port 522 is connected to secondary pump
17 tube 528 and the traction wheel tube 530 is closed; or
18 "state 2" - the inlet port 522 is closed, and the secondary
19 pump tube 528 is connected to the traction wheel tube 530.
20 Secondary pump tube 528 in turn is connected to second
21 electrically operated pump 532, tube 534, electrically
22 operated valve 536 and port 538 and operates analogously to
23 elements 452-462 in Figure 11 provided the two-state valve
24 526 is in state 1.
25

26 In Figure 13, in "state 2", with valve 536 open, and
27 when energized, electrically operated pump 532 forces well
28 fluids through tube 528 and through two-state valve 526 and
29 out tube 530. If valve 540 is open, then the fluids continue
30 through tube 542 and to turbine assembly 544 that causes the
31 traction wheel 546 to move the Smart Shuttle downward in the
32 well. In Figure 13, the "turbine bypass tube" for fluids to
33 be sent to the top of the Smart Shuttle AFTER passage through
34 turbine assembly 544 is NOT shown in detail for the purposes

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1 of simplicity only in Figure 13, but this "turbine bypass
2 tube" is figuratively shown by dashed lines as element 548.

3
4 In Figure 13, the actuating apparatus causing the
5 traction wheel 546 to engage the pipe on command from the
6 surface is shown figuratively as element 550 in Figure 13.
7 The point is that in "state 2", fluids forced through the
8 turbine assembly 544 cause the traction wheel 546 to make
9 the Smart Shuttle go downward in the well, and during this
10 process, fluids forced through the turbine assembly 544 are
11 "vented" to the "up" side of the Smart Shuttle through
12 "turbine bypass tube" 548. Backing rollers 552 and 554 are
13 figuratively shown in Figure 13, and these rollers take side
14 thrust against the pipe when the traction wheel 546 engages
15 the inside of the pipe.

16
17 In the event that seals 500-502 or 504-506 in Figure 13
18 were to lose hydraulic sealing with the pipe, then "state 2"
19 provides yet another means to cause the Smart Shuttle to go
20 downward in the well under control from the surface. The
21 wireline can provide arbitrary pull in the vertical
22 direction, so in this preferred embodiment, "state 2" is
23 primarily directed at making the Smart Shuttle go downward
24 in the well under command from the surface. Therefore,
25 in Figure 13, there are a total of three independent ways
26 to make the Smart Shuttle go downward under command from the
27 surface of the earth ("standard" use of pump 436; "standard"
28 use of pump 532 in "state 1"; and the use of the traction
29 wheel in "state 2").

30
31 The "hybrid pump/wheel device" that is an embodiment of
32 the Smart Shuttle shown in Figure 13 is yet another example
33 of "a conveyance means".
34

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The downward velocity of the Smart Shuttle can be easily determined assuming that electrically operated pump 402 in Figures 9 and 10 are positive displacement pumps so that there is no "pump slippage" caused by pump stalling, cavitation effects, or other pump "imperfections". The following also applies to any pump that pumps a given volume per unit time without any such non-ideal effects. As stated before, in the time interval Δt , a quantity of fluid ΔV_1 is pumped from below the Smart Shuttle to above it. Therefore, if the position of the Smart Shuttle changes downward by ΔZ in the time interval Δt , and with radius a_1 defined in Figure 10, it is evident that:

$$\Delta V_1 / \Delta t = \Delta Z / \Delta t \{ \pi (a_1)^2 \}$$

Equation 1.

$$\text{Downward Velocity} = \Delta Z / \Delta t$$

$$= \{ \Delta V_1 / \Delta t \} / \{ \pi (a_1)^2 \}$$

Equation 2.

Here, the "Downward Velocity" defined in Equation 2 is the average downward velocity of the Smart Shuttle that is averaged over many cycles of the pump. After the Smart Shuttle of the Automated Smart Shuttle System is primed, then the Smart Shuttle and its pump resides in a standing fluid column and the fluids are relatively non-compressible. Further, with the above pump transmission device 508 in Figure 12, or equivalent, the electrically operated pump system will not stall. Therefore, when a given volume of

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1 fluid ΔV is pumped from below the Smart Shuttle to above it,
2 the Shuttle will move downward provided the elastomeric seals
3 like elements 500, 502, 504 and 506 in Figures 9, 11, and 13
4 do not lose hydraulic seal with the casing. Again there are
5 many designs for such seals, and of course, more than two
6 seals can be used along the length of the Smart Shuttle. If
7 the seals momentarily loose their hydraulic sealing ability,
8 then a "hybrid pump/wheel device" as described in Figure 13
9 can be used momentarily until the seals again make suitable
10 contact with the interior of the pipe.

11
12 The preferred embodiment of the Smart Shuttle having
13 internal pump means to pump fluid from below the Smart
14 Shuttle to above it to cause the shuttle to move in the pipe
15 may also be used to replace relatively slow and relatively
16 inefficient "well tractors" that are now commonly used in the
17 industry.

18 19 20 Closed-Loop Completion System

21
22 Figure 14 shows a remaining component of the Automated
23 Smart Shuttle System. It is a portion of a preferred
24 embodiment of an automated system to complete oil and gas
25 wells. It is also a portion of a preferred embodiment of a
26 closed-loop system to complete oil and gas wells. Figure 14
27 shows the computer control of the wireline drum and of the
28 Smart Shuttle in a preferred embodiment of the invention.

29
30 In Figure 14, computer system 556 has typical components
31 in the industry including one or more processors, one or more
32 non-volatile memories, one or more volatile memories, many
33 software programs that can run concurrently or alternatively
34 as the situation requires, etc., and all other features as

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1 necessary to provide computer control of the Automated
2 Shuttle System. In this preferred embodiment, this same
3 computer system 556 also has the capability to acquire data
4 from, send commands to, and otherwise properly operate and
5 control all instruments in the Retrievable Instrumentation
6 Package. Therefore LWD and MWD data is acquired by this same
7 computer system when appropriate. Therefore, in one
8 preferred embodiment, the computer system 556 has all
9 necessary components to interact with the Retrievable
10 Instrumentation Package. In a "closed-loop" operation of the
11 system, information obtained downhole from the Retrievable
12 Instrumentation Package is sent to the computer system that
13 is executing a series of programmed steps, whereby those
14 steps may be changed or altered depending upon the
15 information received from the downhole sensor.

16
17 In Figure 14, the computer system 556 has a cable 558
18 that connects it to display console 560. The display console
19 560 displays data, program steps, and any information
20 required to operate the Smart Shuttle System. The display
21 console is also connected via cable 562 to alarm and
22 communications system 564 that provides proper notification
23 to crews that servicing is required - particularly if the
24 Smart Shuttle chamber 346 in Figure 8 needs servicing that in
25 turn generally involves changing various devices connected to
26 the Smart Shuttle. Data entry and programming console 566
27 provides means to enter any required digital or manual data,
28 commands, or software as needed by the computer system, and
29 it is connected to the computer system via cable 568.

30
31 In Figure 14, computer system 556 provides commands
32 over cable 570 to the electronics interfacing system 572
33 that has many functions. One function of the electronics
34 interfacing system is to provide information to and from the

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1 Smart Shuttle through cabling 574 that is connected to the
2 slip-ring 576, as is typically used in the industry. The
3 slip-ring 576 is suitably mounted on the side of the wireline
4 drum 578 in Figure 14. Information provided to slip-ring 576
5 then proceeds to wireline 580 that generally has 7 electrical
6 conductors enclosed in armor. That wireline 580 proceeds to
7 overhead sheave 582 that is suitably suspended above the
8 Wireline Lubricator System in Figure 8. In particular, the
9 lower portion of the wireline 394 shown in Figure 14 is also
10 shown as the top portion of the wireline 394 that enters the
11 Wireline Lubricator System in Figure 8. That particular
12 portion of the wireline 394 is the same in Figure 14 and in
13 Figure 8, and this equality provides a logical connection
14 between these two figures.

15
16 In Figure 14, electronics interfacing system 572 also
17 provides power and electronic control of the wireline drum
18 hydraulic motor and pump assembly 584 as is typically used
19 in the industry today (that replaced earlier chain drive
20 systems). Wireline drum hydraulic motor and pump assembly
21 584 controls the motion of the wireline drum, and when it
22 winds up in the counter-clockwise direction as observed in
23 Figure 14, the Smart Shuttle goes upwards in the wellbore in
24 Figure 8, and Z decreases. Similarly, when the wireline drum
25 hydraulic motor and pump assembly 584 provides motion in the
26 clockwise direction as observed in Figure 14, then the Smart
27 Shuttle goes down in Figure 8 and Z increases. The wireline
28 drum hydraulic motor and pump assembly 584 is connected to
29 cable connector 588 that is in turn connected to cabling 590
30 that is in turn connected to electronics interfacing system
31 572 that is in turn controlled by computer system 556.
32 Electronics interfacing system 572 also provides power and
33 electronic control of any coiled tubing rig designated by
34 element 591 (not shown in Figure 14), including the coiled

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1 tubing drum hydraulic motor and pump assembly of that coiled
2 tubing rig, but such a coiled tubing rig is not shown in
3 Figure 14 for the purposes of simplicity. In addition,
4 electronics interfacing system 572 has output cable 592 that
5 provides commands and control to drilling rig hardware
6 control system 594 that controls various drilling rig
7 functions and apparatus including the rotary drilling table
8 motors, the mud pump motors, the pumps that control cement
9 flow and other slurry materials as required, and all
10 electronically controlled valves, and those functions are
11 controlled through cable bundle 596 which has an arrow on it
12 in Figure 14 to indicate that this cabling goes to these
13 enumerated items.
14

15 In relation to Figure 14, a preferred embodiment of a
16 portion of the Automated Smart Shuttle System shown in
17 Figure 8 has electronically controlled valves, so that valves
18 392, 384, 378, 364, 360, 344, 340, 336, 332, and 316 as seen
19 from top to bottom in Figure 8, and are all electronically
20 controlled in this embodiment, and may be opened or shut
21 remotely from drilling rig hardware control system 594. In
22 addition, electronics interfacing system 572 also has cable
23 output 598 to ancillary surface transducer and communications
24 control system 600 that provides any required surface
25 transducers and/or communications devices required for the
26 instrumentation within the Retrievable Instrumentation
27 Package. In a preferred embodiment, ancillary surface and
28 communications system 600 provides acoustic transmitters and
29 acoustic receivers as may be required to communicate to and
30 from the Retrievable Instrumentation Package. The ancillary
31 surface and communications system 600 is connected to the
32 required transducers, etc. by cabling 602 that has an arrow
33 in Figure 14 designating that this cabling proceeds to those
34 enumerated transducers and other devices as may be required.

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1 With respect to Figure 14, and to the closed-loop system
2 to complete oil and gas wells, standard electronic feedback
3 control systems and designs are used to implement the entire
4 system as described above, including those described in the
5 book entitled "Theory and Problems of Feedback and Control
6 Systems", "Second Edition", "Continuous (Analog) and
7 Discrete (Digital)", by J.J. DiStefano III, A.R. Stubberud,
8 and I.J. Williams, Schaum's Outline Series, McGraw-Hill,
9 Inc., New York, New York, 1990, 512 pages, an entire copy of
10 which is incorporated herein by reference. Therefore,
11 in Figure 14, the computer system 556 has the ability to
12 communicate with, and to control, all of the above
13 enumerated devices and functions that have been described
14 in this paragraph.

15
16 To emphasize one major point in Figure 14, computer
17 system 556 has the ability to receive information from one
18 or more downhole sensors for the closed-loop system to
19 complete oil and gas wells. This computer system executes
20 a sequence of programmed steps, but those steps may depend
21 upon information obtained from at least one sensor located
22 within the wellbore.

23
24 The entire system represented in Figure 14 provides
25 the automation for the "Automated Smart Shuttle Oil and Gas
26 Completion System", or also abbreviated as the "Automated
27 Smart Shuttle System", or the "Smart Shuttle Oil and Gas
28 Completion System". The system in Figure 14 is the
29 "automatic control means" for the "wireline conveyed shuttle
30 means having retrieval and installation means" (also wireline
31 conveyed Smart Shuttle means having retrieval and
32 installation means"), or simply the "automatic control means"
33 for the "smart shuttle means" (also "Smart Shuttle means").
34

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1 Steps to Complete Well Shown in Figure 6

2
3 The following describes the completion of one well
4 commencing with the well diagram shown in Figure 6. In
5 Figure 6, it is assumed that the well has been drilled to
6 total depth. Furthermore, it is also assumed here that all
7 geophysical information is known about the geological
8 formation because the embodiment of the Retrievable
9 Instrumentation Package shown in Figure 6 has provided
10 complete LWD/MWD information.
11

12 The first step is to disconnect the top of the drill
13 pipe 170, or casing as appropriate, in Figure 6 from the
14 drilling rig apparatus. In this step, the kelly, etc. is
15 disconnected and removed from the drill string that is
16 otherwise held in place with slips as necessary until the
17 next step.
18

19 In addition to typical well control procedures, the
20 second step is to attach to the top of that drill pipe first
21 blowout preventer 316 and top drill pipe flange 320 as shown
22 in Figure 8, and to otherwise attach to that flange 320
23 various portions of the Automated Smart Shuttle System shown
24 in Figure 8 including the "Wiper Plug Pump-Down Stack" 322,
25 the "Smart Shuttle Chamber" 346, and the "Wireline Lubricator
26 System" 374, which are subassemblies that are shown in their
27 final positions after assembly in Figure 8.
28

29 The third step is the "priming" of the Automated Smart
30 Shuttle System as described in relation to Figure 8.
31

32 The fourth step is to retrieve the Retrievable
33 Instrumentation Package. Please recall that the Retrievable
34 Instrumentation Package has heretofore provided all

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1 information about the wellbore, including the depth,
2 geophysical parameters, etc. Therefore, computer system 556
3 in Figure 14 already has this information in its memory and
4 is available for other programs. "Program A" of the computer
5 system 556 is instigated that automatically sends the Smart
6 Shuttle 306 and its Retrieval Sub 308 (see Figure 9) down
7 into the drill string, and causes the electronically
8 controllable retrieval snap ring assembly 310 in Figure 9 to
9 positively snap into the retrieval grove 298 of element 206
10 of the Retrievable Instrumentation Package in Figure 7 when
11 the mating nose 312 of the Retrieval Sub in Figure 9 enters
12 mud passage 198 of the Retrievable Instrumentation Package
13 in Figure 7. Thereafter, the Retrieval Sub has "latched
14 onto" the Retrievable Instrumentation Package. Thereafter,
15 a command is given by the computer system that pulls up on
16 the wireline thereby disengaging mating electrical connectors
17 232 and 234 in Figure 7, and pulling piston 254 through bore
18 258 in the body of the Smart Drilling and Completion Sub in
19 Figure 7. Thereafter, the Smart Shuttle, the Retrieval Sub,
20 and the Retrievable Instrumentation Package under automatic
21 control of "Program A" return to the surface as one unit.
22 Thereafter, "Program A" causes the Smart Shuttle and the
23 Retrieval Sub to "park" the Retrievable Instrumentation
24 Package within the "Smart Shuttle Chamber" 346 and adjacent
25 to the Smart Shuttle chamber door 348. Thereafter, the alarm
26 and communications system 564 sounds a suitable "alarm"
27 to the crew that servicing is required - in this case the
28 Retrievable Instrumentation Package needs to be retrieved
29 from the Smart Shuttle Chamber. The fourth step is completed
30 when the Retrievable Instrumentation Package is removed from
31 the Smart Shuttle Chamber. As an alternative, an automated
32 "hopper system" under control of the computer system can
33 replace the functions of the servicing crew therefore making
34 this portion of the completion an entirely automated process

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1 or as a part of a closed-loop system to complete oil and
2 gas wells.

3
4 The fifth step is to pump down cement and gravel using
5 a suitable pump-down latching one-way valve means and a
6 series of wiper plugs to prepare the bottom portion of the
7 drill string for the final completion steps. The procedure
8 here is followed in analogy with those described in relation
9 to Figures 1-4 above. Here, however, the pump-down latching
10 one-way valve means that is similar to the Latching Float
11 Collar Valve Assembly 20 in Figure 1 is also fitted with
12 apparatus attached to its Upper Seal 22 that provides similar
13 apparatus and function to element 206 of the Retrievable
14 Instrumentation Package in Figure 7. Put simply, a device
15 similar to the Latching Float Collar Valve Assembly 20 in
16 Figure 1 is fitted with additional apparatus so that it may
17 be conveniently deployed in the well by the Retrieval Sub.
18 Wiper plugs are similarly fitted with such apparatus so that
19 they can also be deployed in the well by the Retrieval Sub.
20 As an example of such fitted apparatus, wiper plugs are
21 fabricated that have rubber attachment features so that they
22 can be mated to the Retrieval Sub in the Smart Shuttle
23 Chamber. A cross section of such a rubber-type material
24 wiper plug is generally shown as element 604 in Figure 15;
25 which has upper wiper attachment apparatus 606 that provides
26 similar apparatus and function to element 206 of the
27 Retrievable Instrumentation Package in Figure 7; and which
28 has flexible upper wiper blade 608 to fit the interior of the
29 pipe present; flexible lower wiper blade 610 to fit the
30 interior of the pipe present; wiper plug indentation region
31 between the blades specified by numeral 612; wiper plug
32 interior recession region 614; and wiper plug perforation
33 wall 616 that perforates under suitable applied pressure; and
34 where in some forms of the wiper plugs called "solid wiper

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1 plugs", there is no such wiper plug interior recession region
2 and no portion of the plug wall can be perforated; and where
3 the legends of "UP" and "DOWN" are also shown in Figure 15.
4 In part because the wiper plug shown in Figure 15 may be
5 conveyed downhole with the Retrieval Sub, it is an example
6 of a "smart wiper plug". Further, this smart wiper plug may
7 also possess one or more downhole sensors that provides
8 information to the computer system that controls the well
9 completion process. Accordingly, a pump-down latching
10 one-way valve means is attached to the Retrieval Sub in the
11 Smart Shuttle Chamber, and the computer system is operated
12 using "Program B", where the pump-down latching one-way valve
13 means is placed at, and is released in the pipe adjacent to
14 riser hanger apparatus 315 in Figure 8. Then, under "Program
15 B", perforable wiper plug #1 is attached to the Retrieval Sub
16 in the Smart Shuttle Chamber, and it is placed at and
17 released adjacent to region A in Figure 8. Not shown in
18 Figure 8 are optional controllable "wiper holding apparatus"
19 that on suitable commands fit into the wiper plug indentation
20 region 612 and temporally hold the wiper plug in place within
21 the pipe in Figure 8. Then under "Program B", perforable
22 wiper plug #2 is attached to the Retrieval Sub in the Smart
23 Shuttle Chamber, and it is placed at and released adjacent to
24 region B in Figure 8. Then under "Program B", solid wiper
25 plug #3 is attached to the Retrieval Sub in the Smart Shuttle
26 Chamber, and it is placed at and released adjacent to region
27 C in Figure 8, and the Smart Shuttle and the Retrieval Sub
28 are "parked" in region E of the Smart Shuttle Chamber in
29 Figure 8. Then the Smart Shuttle Chamber is closed, and the
30 chamber itself is suitably "primed" with well fluids. Then,
31 with other valves closed, valve 332 is the opened, and "first
32 volume of cement" is pumped into the pipe forcing the pump-
33 down latching one-way valve means to be forced downward.
34 Then valve 332 is closed, and valve 336 is opened, and a

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1 predetermined volume of gravel is forced into the pipe that
2 in turn forces wiper plug #1 and the one-way valve means
3 downward. Then, valve 336 is closed, and valve 338 opened,
4 and a "second volume of cement" is pumped into the pipe
5 forcing wiper plugs #1 and #2 and the one-way valve means
6 downward. Then valve #338 is closed, and valve 344 is
7 opened, and water is injected into the system forcing wiper
8 plugs #1, #2, and #3, and the one-way valve means downward.
9 Then the latching apparatus of the pump-down latching one-way
10 valve means appropriately seats in latch recession 210 of the
11 Smart Drilling and Completion Sub in Figure 8 that was
12 previously used to latch into place the Retrievable
13 Instrumentation Package. From this disclosure, the pump-down
14 latching one-way valve means has latching means resembling
15 element 208 of the Retrievable Instrumentation Package so
16 that it can latch into place in latch recession 210 of the
17 Smart Drilling and Completion Sub. In the end, the
18 sequential charges of cement, gravel, and then cement are
19 forced through the respective perforated wiper plugs and the
20 one-way valve means and through the mud passages in the drill
21 bit and into the annulus between the drill pipe and the
22 wellbore. Valve 344 is then closed, and pressure is then
23 released in the drill pipe, and the one-way valve means
24 allows the first and second volumes of cement to set up
25 properly on the outside of the drill pipe. After "Program B"
26 is completed, the communications system 564 sounds a suitable
27 "alarm" that the next step should be taken to complete the
28 well. As previously described, an automated "hopper system"
29 under control of the computer system can load the requirement
30 devices into the Smart Shuttle Chamber, and can also suitably
31 control all valves, pumps, etc. so as to make this a
32 completed automated procedure, or as part of a closed-loop
33 system to complete oil and gas wells.

34

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1 The sixth step is to saw slots in the drill pipe similar
2 to the slot that is labeled with numeral 178 in Figure 5.
3 Accordingly, a "Casing Saw" is fitted so that it can be
4 attached to and deployed by the Retrieval Sub. This Casing
5 Saw is figuratively shown in Figure 16 as element 618.
6 The Casing Saw 618 has upper attachment apparatus 620 that
7 provides similar apparatus and mechanical functions as
8 provided by element 206 of the Retrievable Instrumentation
9 Package in Figure 7 - but, that in addition, it also has
10 top electrical connector 622 that mates to the retrieval sub
11 electrical connector 313 shown in Figure 9. These mating
12 electrical connectors 313 and 622 provide electrical energy
13 from the wireline, and command and control signals, to and
14 from the Smart Shuttle as necessary to properly operate the
15 Casing Saw. First casing saw blade 624 is attached to first
16 casing saw arm 626. Second casing saw blade 628 is attached
17 to second casing saw arm 630. Casing saw module 632 provides
18 actuating means to deploy the arms, control signals, and the
19 electrical and any hydraulic systems to rotate the casing saw
20 blades. The casing saw may have one or more downhole sensors
21 to provide measured information to the computer system on the
22 surface. Further, this casing saw may also possess one or
23 more downhole sensors that provides information to the
24 computer system that controls the well completion process.
25 Figure 16 shows the saw blades in their extended "out
26 position", but during any trip downhole, the blades would be
27 in the retracted or "in position". In part because the
28 Casing Saw in Figure 15 may be conveyed downhole with the
29 Retrieval Sub, it is an example of a "Smart Casing Saw".
30 Therefore, during this sixth step, the Casing Saw is suitably
31 attached to the Retrieval Sub, the Smart Shuttle Chamber 346
32 is suitably primed, and then the computer system 556 is
33 operated using "Program C" that automatically controls the
34 wireline drum and the Smart Shuttle so that the Casing Saw is

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1 properly deployed at the correct depth, the casing saw arms
2 and saw blades are properly deployed, and the Casing Saw
3 properly cuts slots through the casing. The "internal pump
4 of the Smart Shuttle" 402 may be used in principle to make
5 the Smart Shuttle go up or down in the well, and in this
6 case, as the saw cuts slots through the casing, it moves up
7 slowly under its own power - and under suitable tension
8 applied to the wireline that is recommended to prevent a
9 disastrous "overrun" of the wireline. After the slots are
10 cut in the casing, the Casing Saw is then returned to the
11 surface of the earth under "Program C" and thereafter, the
12 communications system 564 sounds a suitable "alarm",
13 indicating that crew servicing is required - and in this
14 case, the Casing Saw needs to be retrieved from the Smart
15 Shuttle Chamber. As an alternative, the previously described
16 automated "hopper system" under control of the computer
17 system can replace the functions of the servicing crew
18 therefore making this portion of the completion an entirely
19 automated process, or as part of a closed-loop system to
20 complete oil and gas wells. For a simple single-zone
21 completion system, a coiled tubing conveyed packer can be
22 used to complete the well. For a simple single-zone
23 completion system, only several more steps are necessary.
24 Basically, the wireline system is removed and a coiled tubing
25 rig is used to complete the well.

26
27 The seventh step is to close the first blowout preventer
28 316 in Figure 8. This will prevent any well pressure from
29 causing problems in the following procedure. Then, remove
30 the Smart Shuttle and the Retrieval Sub from the cablehead
31 304, and remove these devices from the Smart Shuttle Chamber.
32 Then, remove the bolts in flanges 376 and 368, and then
33 remove the entire Wireline Lubricator System 374 in Figure 8.
34 Then replace the Wireline Lubricator System with a Coiled

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1 Tubing Lubricator System that looks similar to element 374 in
2 Figure 8, except that the wireline in Figure 8 is replaced
3 with a coiled tubing. At this point, the Coiled Tubing
4 Lubricator System is bolted in place to flange 368 in
5 Figure 8. Figure 17 shows the Coiled Tubing Lubricator
6 System 634. The bottom flange of the Coiled Tubing
7 Lubricator System 636 is designed to mate to upper Smart
8 Shuttle chamber flange 368. These two flanges join at the
9 position marked by numeral 638. The Coiled Tubing Lubricator
10 System in Figure 17 has various additional features,
11 including a second blowout preventer 640, coiled tubing
12 lubricator top body 642, fluid control pipe 644 and its fluid
13 control valve 646, a hydraulic packing gland generally
14 designated by numeral 648 in Figure 17, having gland sealing
15 apparatus 650, grease packing pipe 652 and grease packing
16 valve 654. In the industry, the hydraulic packing gland
17 generally designated by numeral 648 in Figure 17 is often
18 called the "stripper" which has at least the following
19 functions: (a) it forms a dynamic seal around the coiled
20 tubing when the tubing goes into the wellbore or comes out of
21 the wellbore; and (b) it provides some means to change gland
22 sealing apparatus or "packing elements" without removing the
23 coiled tubing from the well. Coiled tubing 656 feeds through
24 the Coiled Tubing Lubricator System and the bottom of the
25 coiled tubing is at the position Y measured from the position
26 marked by numeral 638 in Figure 17. Attached to the coiled
27 tubing a distance d1 above the bottom of the end of the coil
28 tubing is the pump-down single zone packer apparatus 658.
29 In several preferred embodiments of the invention, one or
30 more downhole sensors, related electronics, related batteries
31 or other power source, and one or more communication systems
32 within the pump-down single zone packer apparatus provide
33 information to a computer system controlling the well
34 completion process. The entire system in Figure 17 is then

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1 primed with fluids such as water using techniques already
2 explained. Then, and with the other appropriate valves
3 closed in Figure 17, primary injector tube valve 344 is then
4 opened, and water or other fluids are injected into primary
5 injector tube 342. Then the pressure on top surface of the
6 pump-down single zone packer apparatus forces the packer
7 apparatus downward, thereby increasing the distance Y, but
8 when it does so, fluid $\Delta V2$ is displaced, and it goes up the
9 interior of the coiled tubing and to coiled tubing pressure
10 relief valve 660 near the coiled tubing rig (not shown in
11 Figure 17) and the fluid volume $\Delta V2$ is emptied into a holding
12 tank 662 (not shown in Figure 17). Alternatively, instead of
13 emptying the fluid into the holding tank, the fluid can be
14 suitably recirculated with a suitably connected recirculating
15 pump, although that recirculating pump is not shown in Figure
16 17 for brevity - and such recirculating pump would also
17 minimize the size of the holding tank which is an important
18 feature particularly for offshore use. Still further, the
19 pressure relief valve in the coiled tubing rig is not shown
20 herein, nor is the holding tank, nor is the coiled tubing rig
21 - solely for the purposes of brevity. This hydraulic method
22 of forcing, or "pulling", the tubing into the wellbore will
23 force it down into vertical sections of the wellbore. In
24 such vertical sections of the wellbore, the weight of tubing
25 also assists downward motion within the wellbore. However,
26 of particular interest, this embodiment of the invention also
27 works exceptionally well to force, or "pull", the coiled
28 tubing into horizontal or other highly deviated portions of
29 the wellbore. This is a significant improvement over other
30 methods and apparatus typically used in the industry. This
31 embodiment of the invention can also be used in combination
32 with standard mechanical "injectors" used in the industry.
33 Those mechanical "injectors" provide an axial force on the
34 coiled tubing forcing it into, or out of the well, and there

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1 are many commercial manufactures of such devices. For
2 example, please refer to the volume entitled "Coiled Tubing
3 and Its Applications", having the author of Mr. Scott
4 Quigley, presented during a "Short Course" at the "1999 SPE
5 Annual Technical Conference and Exhibition", October 3-6,
6 Houston, Texas, copyrighted by the Society of Petroleum
7 Engineers, which society is located in Richardson, Texas, an
8 entire copy of which volume is incorporated herein by
9 reference. With reference to Figure 17, the mechanical
10 "injector" 663 (not shown in Figure 17), the guide arch, the
11 reel, the power pack, and the control cabin normally
12 associated with an entire "coiled tubing rig" is not shown in
13 Figure 17 solely for the purpose of brevity. If a mechanical
14 "injector" is used to assist forcing the pump-down single
15 zone packer apparatus 658 into the wellbore, then it is
16 prudent to make sure that there is sufficient hydraulic force
17 applied to the packer apparatus 658 so that the tubing along
18 its entire length is under suitable tension so that it will
19 not "overrun" or "override" the packer apparatus 658. So,
20 even if the mechanical "injector" is assisting the entry of
21 the coiled tubing, the tubing should still be "pulled down
22 into the wellbore" by hydraulic pressure applied to the
23 pump-down single zone packer apparatus 658. Figure 17A
24 shows additional detail in the pump-down single zone packer
25 apparatus 658 which possesses a wiper-plug type elastomeric
26 main body having lobes 659 that slide along the interior of
27 the pipe, and in addition, a portion of the elastomeric unit
28 is permanently attached to the tubing in the region
29 designated as 661 in Figure 17A. The lobes 659 in the
30 elastomeric unit are similar to the "Top Wiper Plug Lobe" 70
31 in Figure 1. Hydraulic force applied to the elastomeric unit
32 causes the tubing to be "pulled" into the pipe disposed in
33 the wellbore, or "forced" into the pipe disposed in the
34 wellbore, and therefore that elastomeric unit acts like a

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1 form of a "tractor" to pull that tubing into the pipe that is
2 disposed in wellbore. The pump-down single zone packer
3 apparatus 658 in Figures 17 and 17A are very simple
4 embodiments of the a "tubing conveyed smart shuttles means"
5 (also "tubing conveyed Smart Shuttle means"). In general, a
6 "tubing conveyed smart shuttle means" also has "retrieval and
7 installation means" for attachment of suitable "smart
8 completion means" for yet additional embodiments of the
9 invention that are not shown herein for brevity. For
10 additional references on coiled tubing rigs, and related
11 apparatus and methods, the interested reader is referred to
12 the book entitled "World Oil's Coiled Tubing Handbook",
13 M.E. Teel, Engineering Editor, Gulf Publishing Company,
14 Houston, Texas, 1993, 126 pages, an entire copy of which is
15 incorporated herein by reference. The coiled tubing rig is
16 controlled with the computer system 556 in Figure 14 and
17 through the electronics interfacing system 572 and therefore
18 the coiled tubing rig and the coiled tubing is under computer
19 control. Then, using techniques already described, the
20 computer system 556 runs "Program D" that deploys the pump-
21 down single zone packer apparatus 658 at the appropriate
22 depth from the surface of the earth. In the end, this well
23 is completed in a configuration resembling a "Single-Zone
24 Completion" as shown in detail in Figure 18 on page 21 of the
25 reference entitled "Well Completion Methods", Lesson 4,
26 "Lessons in Well Servicing and Workover", published by the
27 Petroleum Extension Service, The University of Texas at
28 Austin, Austin, Texas, 1971, total of 49 pages, an entire
29 copy of which is incorporated herein by reference, and that
30 was previously defined as "Ref. 2". It should be noted that
31 the coiled tubing described here can also have a wireline
32 disposed within the coiled tubing using typical techniques in
33 the industry. From this disclosure in the seventh step, it
34 should also be stated here that any of the above defined

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1 smart completion devices could also be installed into the
2 wellbore with a tubing conveyed smart shuttle means or a
3 tubing with wireline conveyed smart shuttle means - should
4 any other smart completion devices be necessary before the
5 completion of the above step. It should be noted that all
6 aspects of this seventh step including the control of the
7 coiled tubing rig, actuators for valves, any automated hopper
8 functions, etc., can be completely automated under the
9 control of the computer system making this portion of the
10 well completion an entirely automated process or as part of a
11 closed-loop system to complete oil and gas wells.
12

13 The eighth step includes suitably closing first blowout
14 preventer 316 or other valve as necessary, and removing in
15 sequence the Coiled Tubing Lubricator System 634, the Smart
16 Shuttle Chamber System 372, and the Wiper Plug Pump-Down
17 Stack 322, and then using usual techniques in the industry,
18 adding suitable wellhead equipment, and commencing oil and
19 gas production. Such wellhead equipment is shown in Figure
20 39 on page 37 of the book entitled "Testing and Completing",
21 Second Edition, Unit II, Lesson 5, published by the Petroleum
22 Extension Service of the University of Texas, Austin,
23 Texas, 1983, 56 pages total, an entire copy of which is
24 incorporated herein by reference, that was previously
25 defined as "Ref. 4" above.
26
27

28 List of Smart Completion Devices

29

30 In light of the above disclosure, it should be evident
31 that there are many uses for the Smart Shuttle and its
32 Retrieval Sub. One use was to retrieve from the drill string
33 the Retrievable Instrumentation Package. Another was to
34 deploy into the well suitable pump-down latching one-way

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1 valve means and a series of wiper plugs. And yet another
2 was to deploy into the well and retrieve the Casing Saw.

3
4 The deployment into the wellbore of the well suitable
5 pump-down latching one-way valve means and a series of wiper
6 plugs and the Casing Saw are examples of "Smart Completion
7 Devices" being deployed into the well with the Smart Shuttle
8 and its Retrieval Sub. Put another way, a "Smart Completion
9 Device" is any device capable of being deployed into the well
10 and retrieved from the well with the Smart Shuttle and its
11 Retrieval Sub and such a device may also be called a "smart
12 completion means". These "Smart Completion Devices" may
13 often have upper attachment apparatus similar to that shown
14 in elements 620 and 622 in Figure 16.

15
16 Any "Smart Completion Device" may have installed within
17 it one or more suitable sensors, measurement apparatus
18 associated with those sensors, batteries and/or power source,
19 and communication means for transmitting the measured
20 information to the Smart Shuttle, and/or to a Retrieval
21 Sub, and/or to the surface. Any "Smart Completion Device"
22 may also have installed within it suitable means to receive
23 commands from the Smart Shuttle and or from the surface of
24 the earth.

25
26 The following is a brief initial list of Smart
27 Completion Devices that may be deployed into the well by the
28 Smart Shuttle and its Retrieval Sub:

- 29 (1) smart pump-down one-way cement valves of all types
30 (2) smart pump-down one-way cement valve with controlled
31 casing locking mechanism
32 (3) smart pump-down latching one-way cement valve
33 (4) smart wiper plug
34

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1 (5) smart wiper plug with controlled casing locking
2 mechanism
3 (6) smart latching wiper plug
4 (7) smart wiper plug system for One-Trip-Down-Drilling
5 (8) smart pump-down wiper plug for cement squeeze jobs
6 with controlled casing locking mechanism
7 (9) smart pump-down plug system for cement squeeze jobs
8 (10) smart pump-down wireline latching retriever
9 (11) smart receiver for smart pump-down wireline
10 latching retriever
11 (12) smart receivable latching electronics package
12 providing any type of MWD, LWD, and drill bit monitoring
13 information
14 (13) smart pump-down and retrievable latching
15 electronics package providing MWD, LWD, and drill bit
16 monitoring information
17 (14) smart pump-down whipstock with controlled casing
18 locking mechanism
19 (15) smart drill bit vibration damper
20 (16) smart drill collar
21 (17) smart pump-down robotic pig to machine slots in
22 drill pipes and casing to complete oil and gas wells
23 (18) smart pump-down robotic pig to chemically treat
24 inside of drill pipes and casings to complete oil and
25 gas wells
26 (19) smart milling pig to fabricate or mill any required
27 slots, holes, or other patterns in drill pipes to
28 complete oil and gas wells
29 (20) smart liner hanger apparatus
30 (21) smart liner installation apparatus
31 (22) smart packer for One-Trip-Down-Drilling
32 (23) smart packer system for One-Trip-Down-Drilling
33 (24) smart drill stem tester
34

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1 From the above list, the "smart completion means"
2 includes smart one-way valve means; smart one-way valve means
3 with controlled casing locking means; smart one-way valve
4 means with latching means; smart wiper plug means; smart
5 wiper plug means with controlled casing locking means; smart
6 wiper plugs with latching means; smart wiper plug means for
7 cement squeeze jobs having controlled casing locking means;
8 smart retrievable latching electronics means; smart whipstock
9 means with controlled casing locking means; smart drill bit
10 vibration damping means; smart robotic pig means to machine
11 slots in pipes; smart robotic pig means to chemically treat
12 inside of pipes; smart robotic pig means to mill any required
13 slots or other patterns in pipes; smart liner installation
14 means; and smart packer means.
15

16 In the above, the term "pump-down" may mean one or both
17 of the following depending on the context: (a) "pump-down"
18 can mean that the "internal pump of the Smart Shuttle" 402 is
19 used to translate the Smart Shuttle downward into the well;
20 or (b) force on fluids introduced by inlets into the Smart
21 Shuttle Chamber and other inlets can be used to force down
22 wiper-plug like devices as described above. The term "casing
23 locking mechanism" has been used above that means, in this
24 case, it locks into the interior of the drill pipe, casing,
25 or whatever pipe in which it is installed. Many of the
26 preferred embodiments herein can also be used in standard
27 casing installations which is a subject that will be
28 described below.
29

30 In summary, a "wireline conveyed smart shuttle means"
31 has "retrieval and installation means" for attachment of
32 suitable "smart completion means". A "tubing conveyed smart
33 shuttle means" also has "retrieval and installation means"
34 for attachment of suitable "smart completion means". If a

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1 wireline is inside the tubing, then a "tubing with wireline
2 conveyed shuttle means" (also "tubing with wireline conveyed
3 Smart Shuttle means") has "retrieval and installation means"
4 for attachment of "smart completion means". As described in
5 this paragraph, and depending on the context, a "smart
6 shuttle means" may refer to a "wireline conveyed smart
7 shuttle means" or to a "tubing conveyed smart shuttle means",
8 whichever may be appropriate from the particular usage. It
9 should also be stated that a "smart shuttle means" may be
10 deployed into a well substantially under the control of a
11 computer system which is an example of a "closed-loop
12 completion system".
13

14 Put yet another way, the smart shuttle means may be
15 deployed into a pipe with a wireline means, with a tubing
16 means, with a tubing conveyed wireline means, and as a
17 robotic means, meaning that the Smart Shuttle provides its
18 own power and is untethered from any wireline or tubing, and
19 in such a case, it is called "an untethered robotic smart
20 shuttle means" (also "an untethered robotic Smart Shuttle
21 means") for the purposes herein.
22

23 It should also be stated for completeness here that any
24 means that are installed in wellbores to complete oil and gas
25 wells that are described in Ref. 1, in Ref. 2, and Ref. 4
26 (defined above, and mentioned again below), and which can be
27 suitably attached to the retrieval and installation means of
28 a smart shuttle means shall be defined herein as yet another
29 smart completion means. For example, in another embodiment,
30 a retrieval sub may be suitably attached to a wireline-
31 conveyed well tractor, and the wireline-conveyed well tractor
32 may be used to convey downhole various smart completion
33 devices attached to the retrieval sub for deployment within
34 the wellbore to complete oil and gas wells.

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1 More Complex Completions of Oil and Gas Wells

2
3 Various different well completions typically used in the
4 industry are described in the following references:

5
6 (a) "Casing and Cementing", Unit II, Lesson 4, Second
7 Edition, of the Rotary Drilling Series, Petroleum
8 Extension Service, The University of Texas at Austin,
9 Austin, Texas, 1982 (defined earlier as "Ref. 1" above)

10
11 (b) "Well Completion Methods", Lesson 4, from the series
12 entitled "Lessons in Well Servicing and Workover",
13 Petroleum Extension Service, The University of Texas at
14 Austin, Austin, Texas, 1971 (defined earlier as "Ref. 2"
15 above)

16
17 (c) "Testing and Completing", Unit II, Lesson 5, Second
18 Edition, of the Rotary Drilling Series, Petroleum
19 Extension Service, The University of Texas at Austin,
20 Austin, Texas, 1983 (defined earlier as "Ref. 4")

21
22 (d) "Well Cleanout and Repair Methods", Lesson 8,
23 from the series entitled "Lessons in Well Servicing and
24 Workover", Petroleum Extension Service, The University
25 of Texas at Austin, Austin, Texas, 1971

26
27 It is evident from the preferred embodiments above, and
28 the description of more complex well completions in (a), (b),
29 (c), and (d) herein, that Smart Shuttles with Retrieval Subs
30 deploying and retrieving various different Smart Completion
31 Devices can be used to complete a vast majority of oil and
32 gas wells. Here, the Smart Shuttles may be either wireline
33 conveyed, or tubing conveyed, whichever is most convenient.
34 Single string dual completion wells may be completed in

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1 analogy with Figure 21 in "Ref. 4". Single-string dual
2 completion wells may be completed in analogy with Figure 22
3 in "Ref. 4". A smart pig to fabricate holes or other
4 patterns in drill pipes (item 19 above) can be used in
5 conjunction with the a smart pump-down whipstock with
6 controlled casing locking mechanism (item 14 above) to
7 allow kick-off wells to be drilled and completed.

8
9 It is further evident from the preferred embodiments
10 above that Smart Shuttles with Retrieval Subs deploying and
11 retrieving various different Smart Completion Devices can be
12 also used to complete multilateral wellbores. Here, the
13 Smart Shuttles may be either wireline conveyed, or tubing
14 conveyed, whichever is most convenient. For a description of
15 such multilateral wells, please refer to the volume entitled
16 "Multilateral Well Technology", having the author of "Baker
17 Hughes, Inc.", that was presented in part by Mr. Randall Cade
18 of Baker Oil Tools, that was handed-out during a "Short
19 Course" at the "1999 SPE Annual Technical Conference and
20 Exhibition", October 3-6, Houston, Texas, having the symbol
21 of "SPE International Education Services" on the front page
22 of the volume, a symbol of the Society of Petroleum
23 Engineers, which society is located in Richardson, Texas,
24 an entire copy of which volume is incorporated herein by
25 reference.

26
27 During more complex completion processes of wellbores,
28 it may be useful to alternate between wireline conveyed smart
29 shuttle means and coiled tubing conveyed smart shuttle means.
30 Of course, the "Wireline Lubricator System" 374 in Figure 8
31 and the Coiled Tubing Lubricator System 634 in Figure 17
32 can be alternatively mated in sequence to the upper Smart
33 Shuttle chamber flange 368 shown in Figures 8 and 17.
34 However, if many such sequential operations, or "switches",

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1 are necessary, then there is a more efficient alternative.
2 One embodiment of this more efficient alternative is to
3 suitably mount on top of the upper Smart Shuttle chamber
4 flange 368, and at the same time, both a Wireline Lubricator
5 System and a Coiled Tubing Lubricator System. There are many
6 ways to design and build such a system that allows for needed
7 space for simultaneously disposing wireline conveyed smart
8 shuttle means and coiled tubing conveyed smart shuttle means
9 within the Smart Shuttle Chamber 346, which chamber is
10 generally shown in Figures 8 and 17, and in other pertinent
11 portion of the system. Yet another embodiment comprises at
12 least one "motion means" and at least one "sealing means" so
13 that the Wireline Lubricator System and the Coiled Tubing
14 Lubricator System can be suitably moved back and forth with
15 respect to the upper Smart Shuttle chamber flange 368, so
16 that the unit that is required during any one step is
17 centered directly over whatever pipe is disposed in wellbore.
18 There are many possibilities. For the purposes herein, a
19 "Dual Lubricator Smart Shuttle System" is one that is
20 suitably fitted with both a Wireline Lubricator System and a
21 Coiled Tubing Lubricator System so that either wireline or
22 tubing conveyed Smart Shuttles can be efficiently used in any
23 order to efficiently complete the oil and gas well. Such a
24 "Dual Lubricator Smart Shuttle System" would be particularly
25 useful in very complex well completions, such as in some
26 multilateral well completions, because it may be necessary to
27 change the order of the completion sequence if unforeseen
28 events transpire. No drawing is provided herein of the "Dual
29 Lubricator Smart Shuttle System" for brevity, but one could
30 easily be generated by suitable combination of the relevant
31 elements in Figures 8 and 17 and at least one "motion means"
32 and at least one "sealing means". Further, any "Dual
33 Lubricator Smart Shuttle System" that is substantially under
34 the control of a computer system that also receives suitable

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1 downhole information is another example of a closed-loop
2 completion system to complete oil and gas wells.

3 4 5 Smart Shuttles and Standard Casing Strings 6

7 Many preferred embodiments of the invention above have
8 referred to drilling and completing through the drill string.
9 However, it is now evident from the above embodiments and the
10 descriptions thereof, that many of the above inventions can
11 be equally useful to complete oil and gas wells with standard
12 well casing. For a description of procedures involving
13 standard casing operations, see Steps 9, 10, 11, 12, 13,
14 and 14 of the specification under the subtitle entitled
15 "Typical Drilling Process".
16

17 Therefore, any embodiment of the invention that pertains
18 to a pipe that is a drill string, also pertains to pipe that
19 is a casing. Put another way, many of the above embodiments
20 of the invention will function in any pipe of any material,
21 any metallic pipe, any steel pipe, any drill pipe, any drill
22 string, any casing, any casing string, any suitably sized
23 liner, any suitably sized tubing, or within any means to
24 convey oil and gas to the surface for production, hereinafter
25 defined as "pipe means".
26

27 Figure 18 shows such a "pipe means" disposed in the
28 open hole 184 that is also called the wellbore here. All the
29 numerals through numeral 184 have been previously defined in
30 relation to Figure 6. A "pipe means" 664 is deployed in the
31 wellbore that may be a pipe made of any material, a metallic
32 pipe, a steel pipe, a drill pipe, a drill string, a casing,
33 a casing string, a liner, a liner string, tubing, or a tubing
34 string, or any means to convey oil and gas to the surface for

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1 production. The "pipe means" may, or may not have threaded
2 joints in the event that the "pipe means" is tubing, but if
3 those threaded joints are present, they are labeled with the
4 numeral 666 in Figure 18. The end of the wellbore 668 is
5 shown. There is no drill bit attached to the last section
6 670 of the "pipe means". In Figure 18, if the "pipe means"
7 is a drill pipe, or drill string, then the retractable bit
8 has been removed one way or another as explained in the next
9 section entitled "Smart Shuttles and Retrievable Drill Bits".
10 If the "pipe means" is a casing, or casing string, then the
11 last section of casing present might also have attached to it
12 a casing shoe as explained earlier, but that device is not
13 shown in Figure 18 for simplicity.

14
15 From the disclosure herein, it should now be evident
16 that the above defined "smart shuttle means" having
17 "retrieval and installation means" can be used to install
18 within the "pipe means" any of the above defined "smart
19 completion means". Here, the "smart shuttle means"
20 includes a "wireline conveyed shuttle means" and/or a
21 "tubing conveyed shuttle means" and/or a "tubing with
22 wireline conveyed shuttle means".

23 24 25 Retrievable Drill Bits and Installation of One-Way Valves

26
27 A first definition of the phrases "one pass drilling",
28 "One-Trip-Drilling" and "One-Trip-Down-Drilling" is quoted
29 above to "mean the process that results in the last long
30 piece of pipe put in the wellbore to which a drill bit is
31 attached is left in place after total depth is reached, and
32 is completed in place, and oil and gas is ultimately produced
33 from within the wellbore through that long piece of pipe.
34 Of course, other pipes, including risers, conductor pipes,

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1 surface casings, intermediate casings, etc., may be present,
2 but the last very long pipe attached to the drill bit that
3 reaches the final depth is left in place and the well is
4 completed using this first definition. This process is
5 directed at dramatically reducing the number of steps to
6 drill and complete oil and gas wells."
7

8 This concept, however, can be generalized one step
9 further that is another embodiment of the invention. As many
10 prior patents show, it is possible to drill a well with a
11 "retrievable drill bit" that is otherwise also called a
12 "retractable drill bit". For the purposes of this invention,
13 a retrievable drill bit may be equivalent to a retractable
14 drill bit in one embodiment. For example, see the following
15 U.S. Patents: U.S. Patent No. 3,552,508, C.C. Brown, entitled
16 "Apparatus for Rotary Drilling of Wells Using Casing as the
17 Drill Pipe", that issued on 1/5/1971, an entire copy of which
18 is incorporated herein by reference; U.S. Patent
19 No. 3,603,411, H.D. Link, entitled "Retractable Drill Bits",
20 that issued on 9/7/1971, an entire copy of which is
21 incorporated herein by reference; U.S. Patent No. 4,651,837,
22 W.G. Mayfield, entitled "Downhole Retrievable Drill Bit",
23 that issued on 3/24/1987, an entire copy of which is
24 incorporated herein by reference; U.S. Patent No. 4,962,822,
25 J.H. Pascale, entitled "Downhole Drill Bit and Bit Coupling",
26 that issued on 10/16/1990, an entire copy of which is
27 incorporated herein by reference; and U.S. Patent
28 No. 5,197,553, R.E. Leturno, entitled "Drilling with Casing
29 and Retrievable Drill Bit", that issued on 3/30/1993, an
30 entire copy of which is incorporated herein by reference.
31 Some experts in the industry call this type of drilling
32 technology to be "drilling with casing". For the purposes
33 herein, the terms "retrievable drill bit", "retrievable drill
34

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1 bit means", "retractable drill bit" and "retractable drill
2 bit means" may be used interchangeably.

3
4 For the purposes of logical explanation at this point,
5 in the event that any drill pipe is used to drill any
6 extended reach lateral wellbore from any offshore platform,
7 and in addition that wellbore perhaps reaches 20 miles
8 laterally from the offshore platform, then to save time and
9 money, the assembled pipe itself should be left in place and
10 not tripped back to the platform. This is true whether or
11 not the drill bit is left on the end of the pipe, or whether
12 or not the well was drilled with so-called "casing drilling"
13 methods. For typical casing-while-drilling methods, see the
14 article entitled "Casing-while-drilling: The next step change
15 in well construction", World Oil, October, 1999, pages 34-40,
16 and entire copy of which is incorporated herein by reference.
17 Further, all terms and definitions in this particular
18 article, and entire copies of each and every one of the 13
19 references cited at the end this article are incorporated
20 herein by reference.

21
22 Accordingly a more general second definition of the
23 phrases "one pass drilling", "One-Trip-Drilling" and
24 "One-Trip-Down-Drilling" shall include the concept that once
25 the drill pipe means reaches total depth and any maximum
26 extended lateral reach, that the pipe means is thereafter
27 left in place and the well is completed. The above
28 embodiments have adequately discussed the cases of leaving
29 the drill bit attached to the drill pipe and completing the
30 oil and gas wells. In the case of a retrievable bit, the bit
31 itself can be left in place and the well completed without
32 retrieving the bit, but the above apparatus and methods of
33 operation using the Smart Shuttle, the Retrieval Sub, and the
34 various Smart Production Devices can also be used in the

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1 drill pipe means that is left in place following the removal
2 of a retrievable bit. This also includes leaving ordinary
3 casing in place following the removal of a retrieval bit and
4 any underreamer during casing drilling operations. This
5 process also includes leaving any type of pipe, tubing,
6 casing, etc. in the wellbore following the removal of the
7 retrievable bit.

8
9 In particular, following the removal of a retrievable
10 drill bit during wellboring activities, one of the first
11 steps to complete the well is to prepare the bottom of
12 the well for production using one-way valves, wiper plugs,
13 cement, and gravel as described in relation to Figures 4, 5,
14 and 8 and as further described in the "fifth step" above
15 under the subtopic of "Steps to Complete Well Shown in
16 Figure 6". The use of one-way valves installed within a
17 drill pipe means following the removal of a retrievable drill
18 bit that allows proper cementation of the wellbore is another
19 embodiment of the invention. These one-way valves can be
20 installed with the Smart Shuttle and its Retrieval Sub, or
21 they can be simply pumped-down from the surface using
22 techniques shown in Figure 1 and in the previously
23 described "fifth step".

24
25 In accordance with the above, a preferred embodiment of
26 the invention is a method of one pass drilling from an
27 offshore platform of a geological formation of interest to
28 produce hydrocarbons comprising at least the following steps:
29 (a) attaching a retrievable drill bit to a casing string
30 located on an offshore platform; (b) drilling a borehole into
31 the earth from the offshore platform to a geological
32 formation of interest; (c) retrieving the retrievable drill
33 bit from the casing string; (d) providing a pathway for
34 fluids to enter into the casing from the geological formation

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1 of interest; (e) completing the well adjacent to the
2 formation of interest with at least one of cement, gravel,
3 chemical ingredients, mud; and (f) passing the hydrocarbons
4 through the casing to the surface of the earth. Such a
5 method applies wherein the borehole is an extended reach
6 wellbore and wherein the borehole is an extended reach
7 lateral wellbore.

8
9 In accordance with the above, a preferred embodiment
10 of the invention is a method of one pass drilling from an
11 offshore platform of a geological formation of interest to
12 produce hydrocarbons comprising at least the following steps:
13 (a) attaching a retractable drill bit to a casing string
14 located on an offshore platform; (b) drilling a borehole into
15 the earth from the offshore platform to a geological
16 formation of interest; (c) retrieving the retractable
17 drill bit from the casing string; (d) providing a pathway for
18 fluids to enter into the casing from the geological formation
19 of interest; (e) completing the well adjacent to the
20 formation of interest with at least one of cement, gravel,
21 chemical ingredients, mud; and (f) passing the hydrocarbons
22 through the casing to the surface of the earth. Such a
23 method applies wherein the borehole is an extended reach
24 wellbore and wherein the borehole is an extended reach
25 lateral wellbore.

26
27 **Figure 18A** shows a modified form of Figure 18 wherein
28 the last portion of the "pipe means" 672 has "pipe mounted
29 latching means" 674. This "pipe mounted latching means"
30 may be used for a number of purposes including at least the
31 following: (a) an attachment means for attaching a
32 retrievable drill bit to the last section of the "pipe
33 means"; and (b) a "stop" for a pump-down one-way valve means
34 following the retrieval of the retrievable drill bit. In

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1 some contexts this "pipe mounted latching means" 674 is also
2 called a "landing means" for brevity. Therefore, an
3 embodiment of this invention is methods and apparatus to
4 install one-way cement valve means in drill pipe means
5 following the removal of a retrievable drill bit to produce
6 oil and gas. It should also be stated that well completion
7 processes that include the removal of a retrievable drill bit
8 may be substantially under the control of a computer system,
9 and in such a case, it is another example of automated
10 completion system or a part of a closed-loop completion
11 system to complete oil and gas wells.
12

13 The above described "landing means" can be used for yet
14 another purpose. This "landing means" can also be used
15 during the one-trip-down-drilling and completion of wellbores
16 in the following manner. First, a standard rotary drill bit
17 is attached to the "landing means". However, the attachment
18 for the drill bit and the landing means are designed and
19 constructed so that a ball plug is pumped down from the
20 surface to release the rotary drill bit from the landing
21 means. There are many examples of such release devices used
22 in the industry, and no further description shall be provided
23 herein in the interests of brevity. For example, relatively
24 recent references to the use of a pump-down plugs, ball
25 plugs, and the like include the following: (a) U.S. Patent
26 No. 5,833,002, that issued on November 10, 1998, having
27 the inventor of Michael Holcombe, that is entitled
28 "Remote Control Plug-Dropping Head", an entire copy of which
29 is incorporated herein by reference; and (b) U.S. Patent
30 No. 5,890,537 that issued on April 6, 1999, having the
31 inventors of Lavaure et. al., that is entitled "Wiper Plug
32 Launching System for Cementing Casing with Liners", an entire
33 copy of which is incorporated herein by reference. After the
34 release of the standard drill bit from the landing means,

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1 a retrievable drill bit and underreamer can thereafter be
2 conveyed downhole from the surface through the drill string
3 (or the casing string, as the case may be) and suitably
4 attached to this landing means. Therefore, during the
5 one-trip-down-drilling and completion of a wellbore, the
6 following steps may be taken: (a) attach a standard rotary
7 drill bit to the landing means having a releasing mechanism
8 actuated by a releasing means, such as a pump down ball;
9 (b) drill as far as possible with standard rotary drill bit
10 attached to landing means; (c) if the standard rotary drill
11 bit becomes dull, drill a sidetrack hole perhaps 50 feet or
12 so into formation; (d) pump down the releasing means, such as
13 a pump down ball, to release the standard rotary drill bit
14 from the landing means and abandon the then dull standard
15 rotary drill bit in the sidetrack hole; (e) pull up on the
16 drill string or casing string as the case may be; (f) install
17 a sharp retrievable drill bit and underreamer as desired by
18 attaching them to the landing means; and (f) resume drilling
19 the borehole in the direction desired. This method has the
20 best of both worlds. On the one-hand, if the standard rotary
21 drill bit remains sharp enough to reach final depth, that
22 is the optimum outcome. On the other-hand, if the standard
23 rotary drill bit dulls prematurely, then using the above
24 defined "Sidetrack Drill Bit Replacement Procedure" in
25 elements (a) through (f) allows for the efficient
26 installation of a sharp drill bit on the end of the drill
27 string or casing string, as the case may be. The landing
28 means may also be made a part of a Smart Drilling and
29 Completion Sub. If a Retrievable Instrumentation Package
30 is present in the drilling apparatus, for example within a
31 Smart Drilling and Completion Sub, then the above steps need
32 to be modified to suitably remove the Retrievable
33 Instrumentation Package before step (d) and then re-install
34 the Retrievable Instrumentation Package before step (f).

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1 However, such changes are minor variations on the preferred
2 embodiments herein described.

3
4 To briefly review the above, many descriptions of
5 closed-loop completion systems have been described. One
6 preferred embodiment of a closed-loop completion system uses
7 methods of causing movement of shuttle means having lateral
8 sealing means within a "pipe means" disposed within a
9 wellbore that includes at least the step of pumping a volume
10 of fluid from a first side of the shuttle means within the
11 pipe means to a second side of the shuttle means within the
12 pipe means, where the shuttle means has an internal pump
13 means. Pumping fluid from one side to the other of the smart
14 shuttle means causes it to move "downward" into the pipe
15 means, or "upward" out of the pipe means, depending on the
16 direction of the fluid being pumped. The pumping of this
17 fluid causes the smart shuttle means to move, translate,
18 change place, change position, advance into the pipe means,
19 or come out of the pipe means, as the case may be, and may
20 be used in other types of pipes.

21
22 In Figure 18B, elements 2, 30, 32, 34, and 36 have been
23 separately identified in relation to Figures 1, 3 and 4.

24
25 In Figure 18B, the Latching Float Collar Valve Assembly
26 21 is related to the Latching Float Collar Valve Assembly 20
27 in Figures 1, 3 and 4. However, in one preferred embodiment,
28 the Latching Float Collar Valve Assembly 21 herein has
29 different dimensions for the unique purposes and applications
30 herein described.

31
32 In Figure 18B, the Upper Seal 23 is related to the Upper
33 Seal 22 of the Latching Float Collar Valve Assembly in
34

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1 Figures 1, 3 and 4. However, the Upper Seal 23 is different
2 in view of the different geometries of pipes described below.

3
4 In Figure 18B, the Latch Recession 25 is related to the
5 Latch Recession 24 Figures 1, 3 and 4. The depth and length
6 of the Latch Recession 25 is different in view of the
7 different geometries of the pipes described below.

8
9 In Figure 18B, the Latch 27 is related to Latch 26 of
10 the Latching Float Collar Valve Assembly in Figures 1, 3
11 and 4. However, the Latch 27 must mate to the new dimensions
12 of the Latch Recession 25.

13
14 In Figure 18B, the Latching Spring 29 is related to the
15 Latching Spring 28 in Figures 1, 3 and 4. However, the
16 Latching Spring 29 must have a different geometry in view of
17 the different Latch Recession 25 and the different Latch 27
18 in Figure 18B.

19
20 Figure 18B shows a "pipe means" 676 deployed in the
21 wellbore. The "pipe means" 676 can also be called simply
22 a pipe for the purposes herein. The pipe 676 has no drill
23 bit attached to the end of the pipe. The "pipe means" is a
24 pipe deployed in the wellbore for any purpose and may be a
25 pipe made of any material, which includes the following
26 examples of such "pipe means": a metallic pipe; a casing; a
27 casing string; a casing string with any retrievable drill bit
28 removed from the wellbore; a casing string with any drilling
29 apparatus removed from the wellbore; a casing string with any
30 electrically operated drilling apparatus retrieved from the
31 wellbore; a casing string with any bicenter bit removed from
32 the wellbore; a steel pipe; an expandable pipe; an expandable
33 pipe made from any material; an expandable metallic pipe; an
34 expandable metallic pipe with any retrievable drill bit

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1 removed from the wellbore; an expandable metallic pipe with
2 any drilling apparatus removed from the wellbore; an
3 expandable metallic pipe with any electrically operated
4 drilling apparatus retrieved from the wellbore; an expandable
5 metallic pipe with any bicenter bit removed from the
6 wellbore; a plastic pipe; a fiberglass pipe; a composite
7 pipe; a composite pipe made from any material; a composite
8 pipe that encapsulates insulated electrical wires carrying
9 electricity and or electrical data signals; a composite pipe
10 that encapsulates insulated electrical wires and at least one
11 optical fiber; any composite pipe that encapsulates insulated
12 wires carrying electricity and/or any tubes containing
13 hydraulic fluid; any composite pipe that encapsulates
14 insulated wires carrying electricity and/or any tubes
15 containing hydraulic fluid and at least one optical fiber;
16 a composite pipe with any retrievable drill bit removed from
17 the wellbore; a composite pipe with any drilling apparatus
18 removed from the wellbore; a composite pipe with any
19 electrically operated drilling apparatus retrieved from the
20 wellbore; a composite pipe with any bicenter bit removed from
21 the wellbore; a drill pipe; a drill string; a drill string
22 with any retrievable drill bit removed from the wellbore; a
23 drill string with any drilling apparatus removed from the
24 wellbore; a drill string with any electrically operated
25 drilling apparatus retrieved from the wellbore; a drill
26 string with any bicenter bit removed from the wellbore; a
27 tubing; a tubing string; a coiled tubing; a coiled tubing
28 left in place after any mud-motor drilling apparatus has been
29 removed from the wellbore; a coiled tubing left in place
30 after any electrically operated drilling apparatus has been
31 retrieved from the wellbore; a liner; a liner string; a liner
32 made from any material; a liner with any retrievable drill
33 bit removed from the wellbore; a liner with any liner
34 drilling apparatus removed from the wellbore; a liner with

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1 any electrically operated drilling apparatus retrieved from
2 the liner; a liner with any bicenter bit removed from the
3 wellbore; any pipe made of any material with any type of
4 drilling apparatus removed from the pipe; any pipe made of
5 any material with any type of drilling apparatus removed from
6 the pipe; or any pipe means to convey oil and gas to the
7 surface for oil and gas production.

8
9 In Figure 18B, pipe means 676 is joined at region 678 to
10 lower pipe section 680. Region 678 could provide matching
11 overlapping threads, welded pipes, or any conceivable means
12 to join the "pipe means" 676 to the lower pipe section 680.
13 The bottom end of the lower pipe section 680 is shown as
14 element 681. The portion of the lower pipe section 680 that
15 mates to the Upper Seal 23 is labeled with legend 682, which
16 may have a suitable radius of curvature, or other suitable
17 shape, to assist the Upper Seal 23 to make good hydraulic
18 contact. The interior of lower pipe section is labeled with
19 element 683. Lower pipe section 680 has Latch Recession 25.
20 The Latching Float Collar Valve Assembly is generally
21 designated as element 21 in Figure 18B, which is also be
22 called the following for the purposes described here:
23 a one-way cement valve; a one-way valve; a pump-down one-way
24 cement valve; a pump-down one-way valve; a pump-down one-way
25 cement valve means; a pump-down one-way valve means;
26 a pump-down latching one-way cement valve means; and a
27 pump-down latching one-way valve means. Particular varieties
28 of one-way valve means include one-way float valves so named
29 because of the Float 32 shown in Figures 1, 3, 4, 18B, and
30 18C. Those varieties of one-way valve means having float
31 valves can be called a "pump-down one-way float valve"; or a
32 "pump-down float valve"; or a "pump-down one-way cement float
33 valve"; or a "pump-down cement float valve"; or a "pump-down
34 float valve means"; or a "pump-down cement float valve

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1 means"; or simply a "cement float valve". Other one-way
2 valve means include various different types of flapper
3 devices to replace the float shown in Figures 1, 4, 18B and
4 18C. All of these different devices may be collectively
5 called a one-way cement valve means or by other similar names
6 defined above including a latching float collar valve
7 assembly.
8

9 The particular variety of a pump-down one-way cement
10 valve shown in Figure 18B latches into place in Latch
11 Recession 25. There are many variations possible for such
12 "stops" for the pump-down one-way cement valve, including
13 element 674 in Figure 18A that can be used as a "stop" for
14 a pump-down one-way valve means following the retrieval of
15 the retrievable drill bit as described above in relation to
16 that Figure 18A.
17

18 In Figure 18B, the wall thickness of the "pipe means"
19 676 is designated by the legend "t1". The wall thickness of
20 the lower pipe section 681 is designated by the legend "t2".
21 The thickness remaining in the wall of the lower pipe section
22 near the Latch Recession 25 is designated by the legend "t3".
23 The portion of the lower pipe section 680 extending below the
24 pipe joining region 678 to the beginning of region 682
25 having curvature has the wall thickness designated by the
26 legend "t4".
27

28 Figure 18C also shows a "pipe means" 676 deployed in
29 the well. In Figure 18C, pipe means 676 is joined at region
30 678 to lower pipe section 680. As in the previous
31 Figure 18B, region 678 could provide matching overlapping
32 threads, welded pipes, or any conceivable means to join the
33 "pipe means" 676 to the lower pipe section 680. The bottom
34

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1 end of lower pipe section is shown as element 681. The
2 interior of lower pipe section is labeled with element 683.

3
4 In Figure 18C, the wall thickness of the "pipe means"
5 676 is designated by the legend "t1". The wall thickness of
6 the lower pipe section 681 is designated by the legend "t2".
7 The thickness remaining in the wall of the lower pipe section
8 near the Latch Recession 25 is designated by the legend "t3".
9 The portion of the lower pipe section 680 extending below the
10 pipe joining region 678 to the beginning of region 682
11 having curvature has the wall thickness designated by the
12 legend "t4".
13

14 As shown in Figures 18B and 18C, the pipe means 676, the
15 the lower pipe section 680, and the joining region 678 are
16 identical for the purposes of discussions herein. As drawn,
17 these are the same pipes in the wellbore.
18

19 Retractable drill bit apparatus 684, also called a
20 retractable drill bit apparatus, is disposed within lower
21 pipe section 680. The retrievable drill bit 686, also called
22 the retractable drill bit, is attached to the retrievable bit
23 apparatus at location 688. The retrievable drill bit has
24 pilot drill bit 702, and first undercutter 692, and second
25 undercutter 694. The pilot bit may be any type of drill bit
26 including a roller cone bit, a diamond bit, a drag bit, etc.
27 which may be removed through the interior of the lower pipe
28 section (when the first and second undercutters are
29 retracted). Portions of such a retractable drill bit
30 apparatus are generally described in U.S. Patent
31 No. 5,197,553, an entire copy of which is incorporated herein
32 by reference. The retrievable drill bit apparatus latch 695
33 latches into place within Latch Recession 25. The
34 retrievable drill bit apparatus possesses a top retrieval sub

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696 so that it can be retrieved by wireline or by drill pipe,
or by other suitable means. The latching mechanism of the
top retrieval sub 696 is analogous to the 'retrievable means
206 that allows a wireline conveyed device from the surface
to "lock on" and retrieve the Retrievable Instrumentation
Package', which is quoted from above in relation to Figure 7.
The latching mechanism of the top retrieval sub 696 allows
mud to flow through it that is analogous to mud passage 198
through the Retrievable Instrumentation Package 194 that is
shown in Figure 7. In one preferred embodiment, the
restriction of mud flowing through the top retrieval sub 696
provides sufficient force to pump the retrievable drill bit
apparatus down into the well. In another preferred
embodiment, the retrievable drill bit apparatus 684 is
installed with the Smart Shuttle that is shown as numeral 306
in Figures 8, 9, and 10. As yet another embodiment of the
invention, a seal 697 within the top retrieval sub 696 allows
it to be pumped down with well fluid, which is ruptured with
sufficient mud pressure after the retrievable drill bit
apparatus 684 properly latches into place. Seal 697 within
the top retrieval sub 696 is not shown in Figure 18C for the
purposes of simplicity. Seal 697 functions similar to seal
fragments 54 and 56 within element 62 in Figure 1 or to seal
130 in element 146 in Figure 4. Upper seal 698 of the
retrievable drill bit apparatus is used to pump down the
apparatus into place with well fluids and to prevent mud from
flowing downward below the upper seal in the region between
the inner portion of lower pipe section 680 and the outer
portion of the retrievable drill bit apparatus (which region
is designated by element 690 in Figure 18C). The portion of
the lower pipe section 680 that mates to the upper seal 698
is labeled with legend 682, which may have a suitable radius
of curvature, or other suitable shape, to assist the upper
seal 698 of the retrievable drill bit apparatus to make a

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1 good hydraulic seal. The outside diameter d1 of the
2 retrievable drill bit apparatus 684 is designated by the
3 legend d1 in Figure 18C.
4

5 The well is drilled and completed using the following
6 procedure. In relation to Figure 18C, the retrievable drill
7 bit apparatus 684 is pumped down through the interior of the
8 pipe means 676 and into the interior of lower pipe section
9 that is labeled with element 683. Drilling fluids, or
10 drilling mud, is used to pump the retrievable drill bit
11 apparatus into place until the retrievable drill bit
12 apparatus latch 695 latches into place within Latch Recession
13 25. Using procedures described in U.S. Patent 5,197,553, and
14 in other similar references described above, the undercutters
15 692 and 694 are then deployed into position. The pilot bit
16 702 is shown in Figure 18C. Then, the "pipe means" 676 is
17 rotated from the surface to drill the wellbore. Other types
18 of key-locking means that locks the retrievable drill bit
19 apparatus into the lower pipe section 680 are not shown for
20 simplicity. Mud is pumped down the interior of the "pipe
21 means" and through the retrievable drill bit apparatus mud
22 flow channel 700, through the mud channels in the pilot bit
23 702, and into the annulus of the borehole 704. The mud
24 channels in the pilot bit are not shown in Figure 18C for the
25 purposes of simplicity. After the desired depth is reached
26 from the surface of the earth, then the retrievable drill bit
27 apparatus is retrieved by wireline or by drill pipe means as
28 described in U.S. Patent No. 5,197,553 and elsewhere.
29

30 Then using techniques described in relation to
31 Figures 1, 3 and 4, then the one-way cement valve
32 means 21 is installed into the interior of lower pipe section
33 that is labeled with element 683. It is pumped down into the
34 well with well fluids until the Latch 695 latches into Latch

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1 Recession 25. Thereafter, various wiper plugs are pumped
2 into the interior of the pipe means 676 as described in
3 relation to Figures 1, 2, 3 and 4 to cement the well into
4 place.

5
6 It is now appreciated that the dimensions of portions of
7 the Latching Float Collar Valve Assembly 21, including the
8 Upper Seal 23, the Latch Recession 25, the Latch 27, and the
9 Latching Spring 29 are to be designed so that the outside
10 diameter d1 of the retrievable drill bit apparatus 684
11 designated by the legend d1 in Figure 18C can be as large as
12 possible. This outside diameter d1 needs to be as large as
13 possible to provide the required strength and ruggedness of
14 the retrievable drill bit apparatus 684. This outside
15 diameter d1 also helps provide the necessary room and
16 strength for the undercutters 692 and 694.

17
18 The retrievable drill bit apparatus 684 in Figure 18
19 may be replaced with any number of different retrievable
20 drill bit apparatus including, but not limited, to: (a) a
21 mud-motor retrievable drilling apparatus; (b) an electric
22 motor retrievable drilling apparatus; and (c) any retrievable
23 drilling apparatus of any type.

24
25 In the above discussion in this Section, a well fluid
26 may include any of the following: water, mud, or cement. In
27 the above discussion in this Section, the term "well fluid"
28 may also be a "slurry material" defined earlier.

29
30 The pump-down one-way valve means may include the
31 following: (a) any types of devices that latch into place
32 near the end the a pipe; (b) any type of devices that
33 "bottom out" against a stop near the end of a pipe;
34 (c) any type of devices that have a "locking key-way"

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1 near the end of a pipe; (d) any type of devices that have
2 overpressure activated "locking dogs" that lock into place
3 near the end of a pipe; (e) any type of pump-down one-way
4 valve means attached to a wireline where sensors are used to
5 sense the position, and to control, the one-way valve;
6 (e) any type of pump-down one-way valve means attached to a
7 coiled tubing; and (f) any type of pump-down one-way valve
8 means attached to a coiled tubing having electrical
9 conductors that are used to sense the position, and to
10 control, the one-way valve.
11

12 Various preferred embodiments provide for an umbilical to
13 be attached to a pump-down one-way valve means where the
14 umbilical explicitly includes a wireline; a coiled tubing;
15 a coiled tubing with wireline; one or more coiled tubings in
16 one concentric assembly with at least one electrical
17 conductor; one or more coiled tubings in one assembly that
18 may be non-concentric; a composite tube; a composite tube
19 with electrical wires in the wall of the composite tube;
20 a composite tube with electrical wires in the wall of the
21 composite tube and at least one optical fiber; a composite
22 tube that is neutrally buoyant in any well fluid present;
23 a composite tube with electrical wires in the wall of the
24 composite tube that is neutrally buoyant in well fluids
25 present; a composite tube with electrical wires in the
26 composite tube and at least one optical fiber that is
27 neutrally buoyant in any well fluids present.
28

29 In view of the above, one preferred embodiment of the
30 invention is the method of drilling and completing a wellbore
31 in a geological formation to produce hydrocarbons from a well
32 comprising at least the following four steps: (a) drilling
33 the well with a retrievable drill bit attached to a casing;
34 (b) removing the retrievable drill bit from the casing;

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1 (c) pumping down a one-way valve into the casing with a well
2 fluid; and (d) using the one-way valve to cement the casing
3 into the wellbore.

4
5 In view of the above, another preferred embodiment of
6 the invention is the method of pumping down a one-way valve
7 with a well fluid into a casing disposed in a wellbore
8 penetrating a subterranean geological formation that is used
9 to cement the casing into the wellbore as at least one step
10 to complete the well to produce hydrocarbons from the well,
11 whereby any retrievable drill bit attached to the casing to
12 drill the well is removed from the casing prior to the step.

13
14 In view of the above, another preferred embodiment of
15 the invention is the method of pumping down a one-way valve
16 with well fluid into a pipe disposed in a wellbore
17 penetrating a subterranean geological formation that is used
18 to cement the pipe into the wellbore as at least one step to
19 complete the well to produce hydrocarbons from the well,
20 whereby the retrievable drill bit attached to the pipe to
21 drill the well is removed from the pipe prior to the step,
22 and whereby the pipe is selected from the group of "pipe
23 means" listed above. Here, the well fluid may be
24 drilling mud, cement, water or a "slurry material" which
25 has been defined earlier.

26
27 In accordance with the above, a preferred embodiment of
28 the invention is a method of one pass drilling from an
29 offshore platform of a geological formation of interest to
30 produce hydrocarbons comprising at least the following steps:
31 (a) attaching a retrievable drill bit to a casing string
32 located on an offshore platform; (b) drilling a borehole into
33 the earth from the offshore platform to a geological
34 formation of interest; (c) retrieving the retrievable drill

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1 bit from the casing string; (d) providing a pathway for
2 fluids to enter into the casing from the geological formation
3 of interest; (e) completing the well adjacent to the
4 formation of interest with at least one of cement, gravel,
5 chemical ingredients, mud; and (f) passing the hydrocarbons
6 through the casing to the surface of the earth. Such a
7 method applies wherein the borehole is an extended reach
8 wellbore and wherein the borehole is an extended reach
9 lateral wellbore.

10
11 In accordance with the above, a preferred embodiment of
12 the invention is a method of one pass drilling from an
13 offshore platform of a geological formation of interest to
14 produce hydrocarbons comprising at least the following steps:
15 (a) attaching a retractable drill bit to a casing string
16 located on an offshore platform; (b) drilling a borehole into
17 the earth from the offshore platform to a geological
18 formation of interest; (c) retrieving the retractable drill
19 bit from the casing string; (d) providing a pathway for
20 fluids to enter into the casing from the geological formation
21 of interest; (e) completing the well adjacent to the
22 formation of interest with at least one of cement, gravel,
23 chemical ingredients, mud; and (f) passing the hydrocarbons
24 through the casing to the surface of the earth. Such a
25 method applies wherein the borehole is an extended reach
26 wellbore and wherein the borehole is an extended reach
27 lateral wellbore.

28
29 It should also be noted that various preferred
30 embodiments have been described which pertain to offshore
31 platforms. However, other preferred embodiments of the
32 invention are used to perform casing drilling from a
33 Floating, Processing Storage and Offloading ("FPSO")
34 Facility; from a Drill Ship; from a Tension Leg Platform

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1 ("TLP"); from a Semisubmersible Vessel; and from any other
2 means that may be used to drill boreholes into the earth from
3 any structure located in a body of water which has a portion
4 above the water line (surface of the ocean, surface of an
5 inland sea, the surface of a lake, etc.) Therefore, methods
6 and apparatus described in this paragraph, and in relation to
7 Figures 5, 6, and 18, are preferred embodiments of "offshore
8 casing drilling means".
9

10 In view of the above, yet another preferred embodiment
11 of the invention is the method of pumping down a one-way
12 valve into a pipe with a fluid that is used as a step to
13 cement the pipe into a wellbore in a geological formation
14 within the earth.
15

16 In view of the above, yet another preferred embodiment
17 of the invention is the method of pumping down a cement float
18 valve into a casing with a fluid that is used as a step to
19 cement the casing into a wellbore in a geological formation
20 within the earth.
21

22 In view of the above, the phrases "one-way valve",
23 "cement float valve", and "one-way cement valve means" may be
24 used interchangeably.
25

26 While the above description contains many specificities,
27 these should not be construed as limitations on the scope of
28 the invention, but rather as exemplification of preferred
29 embodiments thereto. As have been briefly described, there
30 are many possible variations. Accordingly, the scope of the
31 invention should be determined not only by the embodiments
32 illustrated, but by the appended claims and their legal
33 equivalents.
34

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